October 30, 2002

Mr. A. Cayia
Site Vice-President
Point Beach Nuclear Plant
Nuclear Management Company, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 50-266/02-10; 50-301/02-10

Dear Mr. Cayia:

On September 30, 2002, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Point Beach Nuclear Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on October 2, 2002, with you and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the NRC has identified three issues that were evaluated under the risk significance determination process as having very low risk significance (Green). One of those issues was determined not to involve a violation of NRC requirements. The remaining two issues were determined to involve violations of NRC requirements. However, because both violations were non-willful and non-repetitive and because they were entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Point Beach Nuclear Plant facility.

The NRC also identified two findings for which the final risk significance remains to be determined at a later date. The first finding, involving a violation of Technical Specification requirements, concerned Unit 2 having operated for an entire cycle with a pressurizer safety valve that would not have lifted at the required setting. The second finding concerned the quality of the critique for an Alert declaration and Site Area Emergency notification during an

August 1, 2002, emergency preparedness drill. Neither of these findings presented an immediate safety concern.

In response to the terrorist attacks on September 11, 2001, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen licensees' capabilities and readiness to respond to a potential attack. The NRC established a deadline of September 1, 2002, for licensees to complete modifications and process upgrades required by the order. To confirm compliance with this order, the NRC issued Temporary Instruction 2515/148 and over the next year, the NRC will inspect each licensee in accordance with this Temporary Instruction. The NRC continues to monitor overall security controls and may issue additional temporary instructions or require additional inspections should conditions warrant.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 5
Division of Reactor Projects

Docket Nos. 50-266; 50-301
License Nos. DPR-24; DPR-27

Enclosure: Inspection Report 50-266/02-10; 50-301/02-10

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	50-266/02-10; 50-301/02-10
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	July 1 through September 30, 2002
Inspectors:	P. Krohn, Senior Resident Inspector M. Morris, Resident Inspector J. Lara, Senior Resident Inspector, Kewaunee Z. Dunham, Resident Inspector, Kewaunee D. Karjala, Resident Inspector, Prairie Island M. Kunowski, Project Engineer F. Ramirez, Reactor Engineer R. Winter, Reactor Engineer
Approved by:	Kenneth Riemer, Chief Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000266-02-10, IR 05000301-02-10; Nuclear Management Company, LLC; on 07/01-09/30/02, Point Beach Nuclear Plant; Units 1 & 2. Maintenance Rule, Refueling and Other Outage Activities, Surveillance Testing.

This report covers a 3-month period of baseline resident inspection, portions of an announced baseline inservice inspection, and portions of an emergent Unit 1 reactor pressure vessel head inspection. The inspection was conducted by Region III inspectors and the resident inspectors. Three Green findings with two associated Non-Cited Violations (NCVs), and two findings with significance to be determined were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspection Findings

Cornerstone: Mitigating Systems

- Green. Units 1 and 2. The inspectors identified a Non-Cited Violation of 10 CFR 50.65(a)(1) concerning the failure to set (a)(1) goals and monitor against the established goals for the G05 gas turbine (GT), a risk significant maintenance rule component relied upon to meet station blackout and certain Appendix R requirements.

  The issue of failing to set G05 GT (a)(1) goals and monitor against the established goals was more than minor since actual G05 GT equipment problems occurred. However, since the G05 equipment problems were not attributable to a 10 CFR 50.65(a)(1) violation, rather, a maintenance rule violation occurred as a consequence of the G05 GT problems, the performance deficiency could not be processed through the Manual Chapter 0609, "Significance Determination Process." Therefore, in accordance with Appendix B to Inspection Manual Chapter 0612, this maintenance rule violation was considered to be of very low safety significance (Green). (Section 1R12.1)

- Green. Unit 2. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requirements for an inadequate shutdown emergency procedure which failed to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions. Specifically, safety-related shutdown emergency procedures contained operator instructions that could have caused the top of the steam generator U-tubes to become uncovered, thereby affecting the ability of the steam generators to function as a heat sink for removing reactor decay heat.

  The finding was of very low risk significance since NRC senior risk analysts determined that the discrepancy associated with the steam generator narrow range level indication would not have appreciably impacted steam generator heat removal capabilities. (Section 1R20.1)

- Green. Unit 2. The inspectors identified a finding of very low safety significance (Green) concerning the conduct of a partial G02 emergency diesel generator safety injection test while in Mode 1 based on an incomplete and inadequate assessment required by Technical Specification surveillance requirement 3.8.1.5. The finding was determined not to involve a violation of regulatory requirements due to the simplicity of the test and the quality of the pre-job briefing, which effectively met the Technical Specification requirements.

  The finding was determined to be of very low risk significance since the inadequate assessment did not result in a design or qualification deficiency, an actual loss of the safety function, or involve internal or external initiating events. (Section 1R22.1)

Cornerstone: Barrier Integrity

- To Be Determined. Unit 2. In Licensee Event Report 50-301/2002-002-00, the licensee reported the self-revealing discovery during off-site testing that a Unit 2 pressurizer safety valve would not have lifted at the appropriate test pressure. The result was Point Beach Unit 2 having operated with one inoperable pressurizer safety valve for the past operating cycle, December 2000 to April 2002.

  The issue of having an inoperable safety valve installed on the Unit 2 reactor coolant system for an entire operating cycle was more than minor and was characterized as being of at least very low safety significance (Green) since the issue affected the functionality of the reactor coolant system pressure boundary, a physical barrier designed to protect the public from radionuclide releases caused by accidents or events. The issue did not represent an immediate safety concern and was considered an Unresolved Item pending regulatory review of the results of a containment and reactor coolant system pressure response analysis. (Section 4OA3.1)

Cornerstone: Emergency Preparedness

- To Be Determined. Units 1 and 2. The inspectors identified an Unresolved Item concerning the critique of an Alert declaration and Site Area Emergency notification for the August 1, 2002, emergency preparedness drill. This issue did not represent an immediate safety concern and will be considered an Unresolved Item pending further regulatory review by Regional Emergency Preparedness staff. (Section EP6.1)

Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at full power and remained there until July 14, 2002, when power was reduced to 71 percent to support condensate cooler cleaning caused by lake grass fouling. Unit 1 returned to full power later the same day and remained there until July 25, when power was reduced to 98 percent for auxiliary feedwater (AFW) pump surveillance testing. Unit 1 returned to full power operations later the same day and remained there until September 13, when the Unit was shutdown for the U1R27 refueling outage. Unit 1 remained in the refueling outage though the end of the inspection period.

Unit 2 began the inspection period at full power and remained there until July 15, 2002, when power was reduced to 99.6 percent due to a plant process computer system malfunction. Unit 2 was returned to full power operation on July 16 and remained there until July 25 when power was reduced to 98 percent for AFW pump testing. Unit 2 returned to full power operations later the same day and remained there until July 27 when power was reduced to 68 percent for turbine stop, governor, and cross-over steam dump valve testing. Unit 2 returned to full power on July 28 and remained there through the end of the inspection period.

5. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Electrical Power Distribution System 'B' Train Safeguards Complete Walkdown

f. Inspection Scope

During the week of August 5, 2002, the inspectors performed a complete walkdown of the electrical power distribution system 'B' train safeguards to verify proper system configuration. The inspectors interviewed the operations staff concerning operation of the system. The walkdown covered multiple areas, including the control room, primary auxiliary building, the emergency diesel generator (EDG) rooms, the turbine building, and outside support buildings while verifying switch and breaker lineups. The inspectors used licensee periodic checklists (CLs), electrical system diagrams, and system operating procedures during the walkdown to verify that the system was properly configured for full power operations.

b. Findings

No findings of significance were identified.

.2 Emergency Breathing Air System Partial Walkdown

a. Inspection Scope

During the week of August 5, 2002, the inspectors performed a partial system walkdown of the emergency breathing air system to verify proper system configuration. The inspectors used Bechtel Drawing M-209, Sheet 13, "Piping & Instrument Diagram Emergency Breathing Air," and Operating Instruction OI-89 NNSR "Baron II High Pressure Breathing Air Fill System," during the walkdowns to verify that the system was properly configured. During the walkdown, the inspectors also examined valve lineup, configuration, and material condition to verify that the system was capable of performing design basis functions. The inspectors interviewed the control room staff concerning operation of the system. Finally, the inspectors evaluated other elements, such as training materials, to evaluate control room operator readiness to use the system in the event of control room habitability challenges.

b. Findings

No findings of significance were identified.

.3 Component Cooling Water System Partial Walkdown

a. Inspection Scope

During the week of August 19, 2002, the inspectors performed a partial walkdown of the Units 1 and 2 component cooling water (CCW) system to verify proper system configuration. The inspectors used CLs, piping and instrument diagrams, and system operating procedures during the walkdown to verify that the system was properly configured for full power operations.

b. Findings

No findings of significance were identified.

.4 Unit 1 Residual Heat Removal (RHR) System Partial Walkdown

a. Inspection Scope

During the week of August 19, 2002, the inspectors performed a partial walkdown of the Unit 1 RHR system, Train 'B', to verify proper system configuration. The inspectors used CLs and system operating procedures during the walkdown to verify that the system was properly configured for full power operations.

b. Findings

No findings of significance were identified.

.5 G05 Gas Turbine (GT) Generator

a. Inspection Scope

During the week of August 19, 2002, the inspectors performed a partial walkdown of the GT generator system to verify proper system configuration. The inspectors used CLs during the walkdown to verify that the system was properly configured for full power operations.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdown of Selected Fire Zones

a. Inspection Scope

The inspectors walked down the following areas to assess the overall readiness of fire protection equipment and barriers:

- Fire Zone 556, Main Transformer Unit 1
- Fire Zone 698, Main Transformer Unit 2
- Fire Zone 571, Fuel Oil Pump Room
- Fire Zone 771, P-206A and P-207A Fuel Oil Pump Room
- Fire Zone 772, T-176A Day Tank Room
- Fire Zone 776, P-206B and P-207B Fuel Oil Pump Room
- Fire Zone 209, Truck Access Area
- Fire Zone 520, Containment Unit 1, 66'
- Fire Zone 511, Containment Unit 1, 21'
- Fire Zone 156, 1B32 Motor Control Center Room
- Fire Zone 516, Containment Unit 1, 46'
- Fire Zone 318, Cable Spreading Room, 26'

Emphasis was placed on the control of transient combustibles and ignition sources, the material condition of fire protection equipment, and the material condition and operational status of fire barriers used to prevent fire damage or propagation. Area conditions/configurations were evaluated based on information provided in the licensee's "Fire Hazards Analysis Report," August 2001.

The inspectors walked down the listed areas to verify that fire hoses, sprinklers and portable fire extinguishers were installed at their designated locations, were in satisfactory physical condition, were unobstructed, and to verify the physical location and condition of fire detection devices. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were inspected to verify that they were located per Fire Hazards Analysis Report requirements and were in good physical condition. Finally, the inspectors reviewed two corrective action program (CAP) documents that were initiated as a result of this inspection activity.

Corrective action program document CAP029108, “1/2B-30, 480-Volt Motor Control Center Has Gaps Between Base and Access Plate,” which discussed gaps surrounding a metal plate at the base of the safety-related motor control center, was reviewed to determine the potential impact on fire and internal flooding barriers. Corrective action program document CAP 029439, “Documentation in the Point Beach Nuclear Plant Fire Hazards Analysis Report,” which discussed documentation indicating that three ventilation ducts penetrated the barrier between Fire Zones 156 and 157 was reviewed since the actual configuration was that of one duct penetration.

b. Findings

No findings of significance were identified.

.2 Annual Resident Inspector Observation of Unannounced Fire Drill

a. Inspection Scope

The inspectors observed an unannounced drill concerning a fire in the K-1A Waste Gas Compressor cubicle on August 21, 2002, to evaluate the readiness of licensee personnel to prevent and fight fires. The inspectors observed licensee performance in donning protective clothing/turnout gear and self-contained breathing apparatus, deploying firefighting equipment and fire hoses to the scene of the fire, entering the fire area in a deliberate and controlled manner, maintaining clear and concise communications, checking for fire victims and propagation of fire and smoke into other plant areas, smoke removal operations, and the use of pre-planned fire fighting strategies to evaluate the effectiveness of the fire fighting brigade. In addition, the inspectors attended the post-drill debrief to evaluate the licensee’s ability to self-critique fire fighting performance and make recommendations for future improvement. Inspectors verified that deficiencies were identified and entered into the licensee’s CAP. The inspectors also reviewed CAP0029115, “Contamination Control During Fire Drill,” which was initiated as a result of this inspection activity and discussed the possible spread of contamination due to less than adequate contamination controls and survey techniques.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Review of Internal and External Flood Protection Measures

a. Inspection Scope

During the week of July 14, 2002, the inspectors reviewed a sample of areas vulnerable to internal and external flooding. The inspectors reviewed design bases documents and risk analyses. Emphasis was placed on flood protection features such as flood doors, door gaps, and subsoil drains to verify that they were in satisfactory physical condition, unobstructed, and capable of providing an adequate flood barrier. The inspectors walked down the following areas to assess the overall readiness of flood protection equipment and barriers.

- G01 and G02 EDG Rooms
- Turbine Building to Primary Auxiliary Building access doors
- 4160-Volt Vital Switchgear Room access doors

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

During the week of August 19, 2002, the inspectors reviewed thermal performance test data for the Unit 2 'C' and 'D' Component Cooling Water Heat Exchangers (CCHXs). The thermal performance tests were completed at the beginning of a Unit 2 refueling outage when the decay heat load on the components was relatively high. The inspectors reviewed test data and design basis requirements to verify that the CCHXs were capable of performing their safety-related function. The inspectors also reviewed 'C' CCHX eddy current testing results and visually examined the tubesheet, endbell, sacrificial zinc anode, and silt build-up conditions to ensure the ability of the CCHX to remove the design basis heat load. Finally, the inspectors reviewed the frequency of CCHX inspections to verify that inspection intervals were sufficient to detect CCHX degradation prior to the loss of heat removal capabilities below design values.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

Beginning the week of September 9, 2002, the inspectors evaluated the implementation of the licensee's inservice inspection program for monitoring degradation of the Unit 1 reactor coolant system (RCS) boundary and risk significant piping system boundaries based on review of records and in-process observation of non-destructive examinations. The inspectors reviewed modifications; verified appropriate disposition of recordable indications; observed repair activities, and observed or reviewed ultrasonic, visual, and dye penetrant examination results. The inspectors verified that inservice inspection activities were conducted in accordance with the American Society of Mechanical Engineers Code, Section III, Section V, Section IX, and Section XI editions of record for the current 10-year inspection interval. The inspectors also reviewed a sample of inservice inspection related problems documented in the licensee's corrective action program to assess the appropriateness of the corrective actions.

Due to the ongoing U1R27 refueling outage, this inspection activity was not completed by end of the inspection period. Inspector review of inservice inspection activities will be completed and documented in the next integrated inspection report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

During the week of September 9, 2002, the inspectors observed the simulator portion of operator requalification examinations to evaluate the adequacy and proficiency of licensed operator performance. Where failures occurred, the inspectors reviewed licensee actions to remove individuals from control room duties pending remedial training and re-examinations. The inspectors also reviewed the examination, remedial training, and re-examination data for adequacy and accuracy. Finally, the inspectors observed the post-examination critique and evaluated crew involvement in the discussions to assess the rigor of the licensee's self-critique process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

.1 Untimely Development and Approval of (a)(1) Action Plan for G05 GT

a. Inspection Scope

The inspectors reviewed maintenance rule implementation for the G05 GT to verify that component and equipment failures were identified, entered, and scoped within the maintenance rule and that selected systems, structures, and components were properly categorized and classified as (a)(1) or (a)(2) in accordance with 10 CFR 50.65. The inspectors reviewed station logs, maintenance work orders (WOs), condition reports, action requests, and (a)(1) corrective action plans to verify that the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. Additionally, the inspectors reviewed the licensee's performance criteria to verify that the criteria adequately monitored equipment performance and to verify that licensee changes to performance criteria were reflected in the licensee's probabilistic risk assessment.

c. Findings

The inspectors identified a finding of very low safety significance (Green) concerning failure to set (a)(1) goals and monitor against the established goals for the G05 GT, a risk significant maintenance rule component relied upon to meet station blackout and certain Appendix R requirements. The finding represented a failure to set goals and monitor against established goals pursuant to paragraph (a)(1) of 10 CFR 50.65, the Maintenance Rule. A Non-Cited Violation (NCV) of 10 CFR 50.65(a)(1) was identified.

The G05 GT was included in the licensee's maintenance rule program and scoped as providing the risk significant function of supplying power to 13.8-kilovolt bus X-08 during station blackout and vital switchgear room fires. The inspectors also reviewed the Point Beach design basis and noted that the G05 GT does not perform any safety-related functions. Rather, the GT performs two augmented-quality, important-to-safety functions. The first is supplying power to those loads required to achieve and maintain safe reactor shutdown during a station blackout. The second is supplying power to those loads required to achieve and maintain safe reactor shutdown during a plant fire in the vital 4160-Volt switchgear room. Finally, the licensee's most recent probabilistic risk assessment model determined that the G05 GT system accounted for approximately 2.5 percent of the total core damage frequency and had a risk achievement worth of 1.19. Risk achievement worth is the fraction by which the total core damage frequency would increase if the component were out-of-service for an entire year.

The G05 GT is placed in service with the assistance of a starting diesel. The starting diesel, G500, is a V-12 configuration diesel with a common, water-cooled exhaust manifold. The starting diesel vendor specified that the difference in height between the G500 adjacent cylinder heads was to be less than 0.016 inches. During the 12-month period between March 2001 and March 2002, the GT experienced four periods of unavailability due to G500 exhaust manifold gasket coolant leaks. The repetitive leaks were caused by inadequate maintenance and vendor oversight due to exceeding the manufacturer's flatness specification of less than 0.016 inches between the G500 adjacent cylinder heads.

The licensee elevated the G05 GT from (a)(2) to (a)(1) status on January 17, 2002, when a system engineer determined that earlier G500 starting diesel failures met the definition of repetitive maintenance preventable functional failures. The system engineer reasoned that if proper G500 maintenance had been performed, the flatness of the exhaust manifold connections to the head exceeding the manufacturer's specifications would have been noted and proper actions taken to correct the condition prior to returning the G500 and G05 GT system to service. The system engineer initiated CAP001899, "Gas Turbine System Meets Criteria for (a)(1) Status," to document the transition to (a)(1) status and to track the subsequent corrective actions. The system engineer also wrote CAP028988, "Inadequate Vendor Oversight," on August 8, 2002, to document the lack of vendor oversight as having been identified as the cause of several major issues, including two of the four G500 starting diesel exhaust manifold leaks.

Corrective Action Item CA003554 was assigned to the GT system engineer on January 18, 2002, to prepare an action plan to return the GT system to (a)(2) status. A due date of March 15, 2002, was originally assigned but was extended to April 16 to allow inclusion of the March 2002 G500 failure into the (a)(1) action plan. On April 24, the system engineer requested another due date extension to the (a)(1) action plan to allow input by the facilities general supervisor. The system engineer's supervisor approved the second extension request on May 14, stating that the second extension was necessary to allow support of other higher priority work associated with the troubleshooting and repair of the G02 (Unit 2, 'A' train) EDG. The GT system engineer subsequently completed the draft (a)(1) action plan on July 15, and Corrective Action Item CA003554 was closed on July 16. Revision 0 of the (a)(1) action plan was submitted to the maintenance rule expert panel on August 5, 2002. Initial comments were incorporated and the (a)(1) action plan was again discussed during an expert panel meeting on September 12, 2002. The (a)(1) action plan received final expert panel approval on September 13, a period of 7 months and 27 days after the GT system was first declared (a)(1).

Analysis

For each period of GT unavailability between March 2001 and March 2002 that began with a G500 coolant leak, the G05 GT was returned to service, on average, within a period of 189 hours or approximately 8 days. In addition, other problems contributed to G05 GT unavailability, including a fuel oil leak on March 22, 2002; a combustion flame out alarm on April 1, 2002; a failure to start on April 3, 2002; and a failure to synchronize to the 13.8-kilovolt bus on August 2, 2002. Given the number, variety, and complexity of G05 problems, the inspectors determined that the licensee had made reasonable efforts to return the GT to service following each individual period of unavailability. Nonetheless, failure to approve the (a)(1) action plan between January 17, 2002, and September 13, 2002, represented a failure to set goals and then monitor G05 GT performance against those established goals. The inspectors determined that following January 17, 2002, 10 CFR 50.65(a)(2) was no longer applicable to the G05 GT system since the repetitive maintenance functional failures had demonstrated that the performance and condition of the GT system was not being effectively controlled through the performance of appropriate preventative maintenance. Finally, the inspectors considered the failure to approve a G05 GT (a)(1) action plan within nearly 8 months after first declaring the system (a)(1) to be untimely and excessive given that the maintenance rule program defined the G05 GT system as risk significant.

The inspectors determined that the licensee's performance deficiency was failing to set G05 GT (a)(1) goals and monitor against the established goals. This deficiency was more than minor and a finding since actual G05 GT equipment problems occurred. However, since the G05 equipment problems were not attributable to a 10 CFR 50.65(a)(1) violation, rather, a maintenance rule violation occurred as a consequence of the G05 GT problems, the performance deficiency cannot be processed through the Inspection Manual Chapter 0609, "Significance Determination Process." Therefore, in accordance with Appendix B to Inspection Manual Chapter 0612, such maintenance rule violations are considered to be of very low safety significance (Green). This finding also has cross-cutting issue implications relating to problem identification and resolution, in that, while elevation of the G05 GT system to (a)(1) status was widely understood by plant personnel, dedication of resources to develop, approve, and issue the (a)(1) action plan was delayed.

Enforcement

10 CFR 50.65(a)(1), requires, in part, that the holders of an operating license monitor the performance or condition of structures, systems, or components within the scope of the rule as defined by 10 CFR 50.65(b), against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken.

Contrary to the above, from January 17 to September 13, 2002, goals were not set nor monitored against. Specifically, the licensee failed to set goals and to perform monitoring for the G05 GT system although the system was classified as being within the scope of the monitoring program on January 17, 2002, the time at which the preventative maintenance program was shown to be ineffective due to repeat maintenance-preventable function failures. Since this violation was determined to be of very low risk significance (Green) and because the licensee entered the finding into its CAP, the violation was treated as a Non-Cited Violation (NCV 50-266/02-10-01; 50-301/02-10-01) consistent with Section VI.A. of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action system as CAP029493, “Gas Turbine (a)(1) Action Plan Not Written and Approved In A Timely Manner.”

.2 Metering, Relaying, and Regulation System

a. Inspection Scope

During the week of September 16, 2002, the inspectors reviewed the implementation of the maintenance rule to verify that component and equipment failures in the metering, relaying, and regulation system were identified, entered, and scoped within the rule and that the system was properly categorized as (a)(1) in accordance with 10 CFR 50.65. The inspectors reviewed condition reports, station logs, CAP documents, and other documents related to the maintenance rule and the metering, relaying, and regulation system to verify that the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities, to verify that scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the licensee's program for conducting maintenance risk safety assessments to verify that the licensee's planning, risk management tools, and the assessment and management of on-line risk were adequate. The inspectors also reviewed licensee actions to address increased on-line risk when equipment was out-of-service for maintenance, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, to verify that the actions were accomplished when on-line risk was increased due to maintenance on risk-significant systems, structures, and components. The maintenance risk assessments for work planned for the weeks beginning on the dates listed below were reviewed:

- July 7, 2002. This work included replacement of a Unit 2 high pressure turbine first stage pressure transmitter, the repair of a failed high, reactor coolant system wide range cold leg resistance temperature detector, troubleshooting and testing of the G05 GT, and the beginning of modification activities associated with the control room ventilation envelope.

- July 14, 2002. This work included preventative maintenance and surveillance testing of 1P-11A CCW pump, the G04 EDG, the 1P-2A charging pump, and power range nuclear instrument axial offset testing.

- July 21, 2002. This work included preventative maintenance and surveillance testing of a station air compressor, reactor protection and safeguards logic testing, AFW pump testing, and modification of the control room ventilation system.

- July 28, 2002. This work included preventative maintenance and surveillance testing of the 2P-29 turbine-driven AFW pump, performance testing of the D-106 yellow instrument bus safety-related battery, changing of the P-38A motor-driven AFW pump supply breaker, and modification of the control room ventilation system.

- August 4, 2002. This work included change out, preventative maintenance, and surveillance testing of the P-32A service water (SW) pump, emergent work on the 1P-29 turbine-driven AFW pump, 1P-15A and 1P-15B safety injection (SI) pump venting, and removal from service of the 1A04 to 2A04 bus tie breaker, 1A52-52.

- August 11, 2002. This work included preventative maintenance and surveillance testing of the north SW Zurn strainer and replacement of the stem, plug, and seat ring on a SI system test line flow control valve.
- August 18, 2002. This work included preventative maintenance and surveillance testing of the 'C' CCW heat exchanger, the Unit 1 'A' and 'B' RHR pumps, the Unit 2 'A' CCW, the Unit 1 'A' and 'B' SI pumps, and a check of the alignment between the G02 diesel engine and electrical generator.

- August 25, 2002. This work included preventative maintenance and surveillance testing of safety-related protective relays associated with safeguards Bus 1A-05, venting of Units 1 and 2 SI systems, and testing of Unit 2 safeguards bus undervoltage, Train ‘A’, reactor protection and safeguards logic circuitry.

- September 15, 2002. This work included the Unit 1, U1R27 refueling outage while Unit 2 remained at full power. Work included integrated SI testing for the Unit 1 ‘A’ and ‘B’ safeguards trains and maintenance on SW overboard valve, SW-146. When single trains of Unit 1 safeguards equipment were removed from service for maintenance, the inspectors verified that the remaining, redundant trains were treated and maintained as protected equipment. The inspectors also reviewed the risk impact of a work control sequence error which resulted in the inadvertent isolation of the non-safety condensate storage tank supply to all of the Unit 2 AFW pumps.

- September 22, 2002. This work included the Unit 1, U1R27 refueling outage while Unit 2 remained at full power. This work included preventative maintenance, post-maintenance, and surveillance testing of the Unit 2 turbine trip system, the G02 EDG fuel oil transfer pump, and safeguards busses 1B-04 and 1A-06. When single trains of Unit 1 safeguards equipment were removed from service for maintenance, the inspectors verified that the remaining, redundant trains were treated and maintained as protected equipment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 10 CFR Part 21Notification Relating to Greyboot ‘A’ Connectors

a. Inspection Scope

During the week of July 1, 2002, the inspectors reviewed operability determination and CAP documents associated with CAP028606, “Potential 10 CFR Part 21 Notification Relating to Greyboot ‘A’ Connectors,” to determine if the Unit 2 hydrogen analyzers, HYA-00964/965/966/967, met radiation exposure environmental qualification requirements. The inspectors compared the total test irradiation dose with the Point Beach design basis requirements to verify that the actual test levels continued to bound the sum of the radiation exposures resulting from design basis accidents and normal operations. In addition, the inspectors reviewed the CAP document history to verify the licensee had placed the proper emphasis on determining connector operability, when first informed of the 10 CFR Part 21 issue from the Greyboot connector vendor.

b. Findings

No findings of significance were identified.

.2 Unit 2 Spray Addition Tank Outlet Flow Meter False Indiction

a. Inspection Scope

During the week of August 5, 2002, the inspectors reviewed Operability Determination OPR-000022, “2FIT-930, Spray Add Flow FIT, False Indication,” to verify that the containment spray system remained capable of performing its intended safety function despite previous operating experience which indicated that false control room containment spray flow indications could occur when operating the 2P-15A SI pump in the piggy-back mode. The inspectors reviewed the source of the control room false containment spray indication, piping vibration in the local area of the flow transmitter, to verify that no fatigue concerns existed and the integrity of the containment spray piping would be maintained. The inspectors reviewed the safety-related function of 2FIT-930, design basis documents, and emergency operating and critical safety function procedural guidance to verify that, despite a false flow indication, the containment spray system remained capable of performing the intended safety function. Finally, the inspectors reviewed the last 2P-15A quarterly surveillance test results to verify that no abnormal 2FIT-930 flow indications had occurred while running the 2P-15A SI pump.

b. Findings

No findings of significance were identified.

.3 Evaluation of Unit 1 Containment Sump 'A' Increased Leakage

a. Inspection Scope

During the weeks of August 5 and August 19, 2002, the inspectors evaluated the potential sources of an approximate 0.02 gallons per minute (GPM) leak that had appeared in the Unit 1 containment during March 2002. The inspectors reviewed several aspects of the licensee's troubleshooting plan and the subsequent results to verify that all potential sources of leakage had been considered and evaluated. In addition, the inspectors performed a walkdown of accessible portions of the sump 'A' drain piping located in the primary auxiliary building. Included in the inspectors’ evaluation were reviews of:

- the results of two primary containment inspections specifically performed to identify the source of the leakage
- chemistry records and analyses as well as interviews with chemistry personnel to evaluate the sump 'A' contents as characteristic of primary, secondary, CCW, or SW related leakage
- containment fan coil unit inspection results
- shroud cooling fan inspection and cooling water isolation results
- the primary containment floor drain configuration and the inputs to sump 'A'
- the licensee's as-low-as-is-reasonably-achievable rationale for not performing a steam generator, pressurizer and reactor coolant pump vault entry at power to determine the source of the leak
- the licensee's plans to perform a loop inspection at the next available opportunity, either the next forced shutdown or the Unit 1 refueling outage

- the CAP history associated with the Unit 1 sump 'A' level increase investigation.

Finally, the inspectors reviewed CAP028997, “Scaffold in U1 RHR HX Cubicle On The -5 Foot Level Not Labeled,” which was initiated as a result of this inspection activity and discussed a scaffold in the vicinity of the Unit 1 common emergency core cooling system suction header, a scaffold of which the licensee had been unaware.

b. Findings

No findings of significance were identified.

.4 Operability of Valve 2AF-114 Following Identification of a Linear Crack on Valve Body

a. Inspection Scope

During the weeks of July 29, 2002, the inspectors reviewed the operability determination associated with CAP028877, “Linear Indication Found on Valve 2AF-114,” to evaluate the significance of a linear crack indication found on Valve 2AF-114, a Unit 2 turbine-driven AFW pump mini-recirculation check valve. The inspectors interviewed nondestructive testing and system engineering personnel to evaluate the characteristics of the indication and to determine whether the indication was related to manufacturing or inservice activities. The inspectors also reviewed the decision to declare the turbine-driven AFW pump inoperable until repairs could be completed. Finally, the inspectors reviewed a U2R25 refueling outage weld package associated with 2AF-114 to determine previous opportunities to have dispositioned the linear indication. Further discussion concerning the thoroughness and timeliness of licensee corrective actions associated with CAP028877 is provided in Section 4OA2.2 of this report.

b. Findings

No findings of significance were identified.

.5 P-32A SW Pump Motor Current Imbalance

a. Inspection Scope

During the week of August 5, 2002, the inspectors reviewed the operability determination associated with CAP028995, “Routine Maintenance Procedure Head Out of Spec Motor Amp Current for P32A SW Pump,” which discussed a motor current imbalance for safety-related ‘A’ SW Pump, P-32A. The inspectors reviewed the magnitude of the imbalance and compared this against industry guidance to evaluate the long term affects on P-32A operability. The inspectors also reviewed CAP028999, “Procedural Acceptance Criteria Too Conservative,” to evaluate the adequacy of licensee routine maintenance procedures.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Unit 2 Spray Additive Tank Flow Meter

a. Inspection Scope

During the week of July 22 and 29, 2002, the inspectors reviewed CAP documents and WOs associated with main control board indicator 2FIT-930, "Spray Additive Tank Delivery Line Flow," to understand the potential effects of a false control room reading on operator's ability to respond to a Unit 2 design basis, off-normal, or transient events. Specifically, the inspectors reviewed the applicability of a false 2FIT-930 reading of 27 GPM, noted while operating the 2P-15A SI pump with the containment spray pumps secured, on the operator's ability to reduce containment overpressure and diagnose containment spray system malfunctions. The inspectors also examined the age of the corrective actions documents, some of which were six years old, and the associated WOs, some of which were still in the planning stages, to ascertain the licensee's timeliness in addressing the false main control board indication. The inspectors reviewed design basis requirements, emergency operating, abnormal operating, alarm response, and critical safety procedures to determine the extent to which 2FIT-930 was used in responding to Unit 2 off-normal and transient conditions. Finally, the inspectors reviewed CAP028875, "WOs for FIT-930 (Control Board Indicators) Are Over 6 years Old," which was initiated as a result of this inspection activity and discussed plans to have verified the false indication during the last Unit 2 refueling outage, a task which was not properly scheduled or completed.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

.1 Installation of Fish Deterrent System to Intake Structure

a. Inspection Scope

During the week of July 1, 2002, the inspectors reviewed Modification Request MR 02-007, "Fish Deflection System for the Intake Crib," to verify that the design bases, licensing bases, and performance capability of risk significant structures, systems, or components had not been degraded because of the modifications, and to verify that the modifications performed during increased risk-significant configurations did not place the plant in an unsafe condition.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT) (71111.19)

.1 Unit 1 CCW Pump P-11A

a. Inspection Scope

During the week of July 15, 2002, the inspectors reviewed PMT activities associated with Unit 1 CCW pump, P-11A, following an oil change, bearing flush, and cleaning of the motor air intake grills. The inspectors reviewed WO 0202670 and design basis requirements to verify that the post-maintenance test was appropriate for the scope of work performed. In addition, the inspectors observed portions of Inservice Test (IT) 12, "Component Cooling Water Pumps and Valves (Quarterly) Unit 1," Revision 26, to verify that the pump remained capable of meeting the intended safety function and had been returned to service in an operable condition. The inspectors also reviewed the completed test documentation to verify that the test data were complete, appropriately verified, and met the requirements of the test procedure.

b. Findings

No findings of significance were identified.

.2 Unit 1 CCW Pump P-11B

a. Inspection Scope

During the week of July 22, 2002, the inspectors reviewed PMT activities associated with Unit 1 CCW pump, P-11B, following an oil change, bearing flush, and cleaning of the motor air intake grills. The inspectors reviewed WO 0202672, which specified the maintenance work and post-maintenance test requirements to ensure that the test was appropriate for the scope of work performed.

b. Findings

No findings of significance were identified.

.3 Maintenance Overhaul and Motor Replacement - 'A' SW Pump

a. Inspection Scope

During the week of August 5, 2002, the inspectors reviewed PMT activities and design basis requirements associated with the change out and repair of the P-32A SW pump to verify that the test was appropriate for the scope of work performed. The inspectors observed portions of the P-32A PMT performed in accordance with IT-07A, "P-32A Service Water Pump (Quarterly)," Revision 11, to verify that the pump remained capable of performing the intended safety function. The inspectors reviewed the completed test documentation to verify that the test data were complete, appropriately verified, and met the requirements of the test procedure. Following post-maintenance activities, the inspectors performed a walkdown of P-32A to verify that the pump had been restored to an operable condition.

b. Findings

No findings of significance were identified.

.4 Unit 2 ‘B’ RHR Pump Oil Change

a. Inspection Scope

During the week of September 2, 2002, the inspectors observed PMT activities associated with WO 9943660, “Change Oil in 2P-10B RHR Pump,” and Inservice Test IT-04, “Low Head Safety Injection Pumps and Valves,” to verify that the post-maintenance test was appropriate for the scope of work performed, the pump remained capable of performing the intended safety function, and the pump was restored to an operable condition.

b. Findings

No findings of significance were identified.

.5 Unit 1 SI System Throttle Valve SI-829C

a. Inspection Scope

During the week of August 12, 2002, the inspectors observed some of the maintenance and post-maintenance test activities performed on 1SI-829C, a Unit 1 SI system throttle valve, to verify that the test was appropriate for the scope and type of maintenance performed. The valve was a 2½” manual globe valve; the maintenance performed included replacement of the stem and disc, lapping of the seat, repacking, and torquing of the body-to-bonnet nuts. The PMT included a skill-of- the-craft adjustment of the packing/gland nuts immediately after reassembly of the valve and a visual check for external leakage during IT 01, “High Head Safety Injection Pumps and Valves (Quarterly) Unit 1,” Revision 48, on August 21.

b. Findings

No findings of significance were identified.

.6 Removal of Internals from AF-117 AFW Pump Common Mini-Recirculation Header Check Valve

i. Inspection Scope

During the week of September 16, 2002, the inspectors reviewed PMT activities associated with the AFW pump common mini-recirculation header check valve, AF-117, to verify that removal of the valve internals would not create the potential for a common mode failure of the recirculation return header. The inspectors reviewed completed WO 0212107-MR02-029 to verify that the procedure had been properly reviewed and approved and to ensure that the acceptance criteria were consistent with applicable licensing design basis requirements. The inspectors also reviewed safety evaluations SCR-2002-0359 and SCR-2002-0377 to verify that the modification and PMT activities had been performed in accordance with design basis requirements and to verify that the AFW system would remain capable of performing the intended safety functions.

b. Findings

No findings of significance were identified.

.7 RHR-700 Leakoff Line Repair

a. Scope

During the week of September 27, 2002, the inspectors reviewed PMT activities associated with the valve bonnet leak-off line from residual heat removal system Valve 1RH-700, "To P-10A/B RHR Pump Suction Header," to ensure a satisfactory pressure boundary following two previously failed weld attempts. The inspectors reviewed WO 9937845 and the subsequent amendments to verify that the installation of a Swedgelok fitting and a third weld attempt were successful and resulted in the valve maintaining a satisfactory pressure boundary. The inspectors also reviewed CAP029556, "RH-700 Leakoff Line Weld Could Not Be Made Due To Moisture In Line," to ensure that the licensee had included the first two failed weld attempts into their CAP. The inspectors reviewed completed WO 9937845 to verify that the procedure has been properly reviewed and approved and to ensure that the acceptance criteria were consistent with applicable licensing and design basis requirements. In addition, the inspectors examined the valve following final repairs to ensure that there was no leakage from the weld area.

The inspector reviewed the WO documentation for accuracy after the welds had been completed. The inspectors reviewed the documentation to insure that it accurately reflected the work as it was performed. The inspectors reviewed the licensee's plan to correct the documentation prior to closing the package.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 (Closed) Unresolved Item (URI) 50-301/02-06-01: Use of steam generator narrow range level detector during cold shutdown plant conditions. This item was previously discussed in Inspection Report 50-266/02-06: 50-301/02-06, Section 1R20.1, and concerned the failure to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions. Specifically, safety-related shutdown emergency procedures contained operator instructions that could have caused the top of the steam generator

U-tubes to become uncovered, thereby affecting the ability of the steam generators to function as a heat sink for removing reactor decay heat.

During the U2R25 refueling outage, the inspectors identified two time periods where the steam generators had been credited as an alternate method of reactor decay heat removal. Each time period was applied to the Significance Determination Process, Inspection Manual Chapter 0609, Appendix G, Phase 1 worksheets. The first period near the beginning of the outage was forwarded to the Region III Senior Risk Analyst for quantitative risk assessment. Region III and Nuclear Reactor Regulation senior risk analysts determined that the issue associated with the first time period was of very low risk significance (Green) since the level discrepancy associated with the steam generator narrow range level indication would not have appreciably impacted steam generator heat removal capabilities. The finding associated with the second period near the end of the outage was previously characterized as having very low safety significance (Green). Since one technical issue was common to both time periods and both periods were determined to be of very low risk significance (Green), the single technical issue of failing to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions was treated as one finding of very low risk significance (Green).

Appendix B, Criterion V, of 10 CFR Part 50, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Contrary to the above, from April 14, 2002, at 4:30 p.m. to April 15, at 4:45 p.m. and May 4, 2002, at 1:00 p.m. to May 10, at 2:30 a.m., periods when the steam generators were credited as an alternate method of reactor decay heat removal during the Unit 2 U2R25 refueling outage, Shutdown Emergency Procedure 3.0, “Loss of All Alternating Current Power to a Shutdown Unit,” Revision 13, was not appropriate to the circumstances. Specifically, Shutdown Emergency Procedure 3.0, Steps 5b and 8b, contained inadequate procedure guidance to ensure the top of the secondary side of the steam generator U-tubes remained covered with water during a loss of all alternating current power. Failure to maintain the top of the U-tubes covered with water impacted the ability of the steam generators to function as a heat sink to remove reactor decay heat.

Since the discrepancy associated with the steam generator narrow range level indication would not have appreciably impacted steam generator heat removal capabilities and Agency senior reactor analysts determined the issue to be of very low risk significance (Green), this violation is being treated as a Non-Cited Violation (NCV 50-301/02-10-02) consistent with Section VI.A. of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action system as AR 3112, “Steam Generator Narrow Range Level Uncertainty at Lower Temperature.”

.2 Review of Selected U1R27 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed work activities associated with the Unit 1 refueling outage, U1R27, which began on September 13 and continued through the end of this reporting period. The inspectors assessed the adequacy of outage-related activities, including configuration management, clearances and tagouts, and RCS reduced inventory operations. Additionally, the inspectors reviewed refueling operations for implementation of risk management, preparation of contingency plans for loss of key safety functions, conformance to approved site procedures, and compliance with Technical Specifications (TSs). The inspectors also verified compliance with commitments made during licensee response to Generic Letter 88-17, "Loss of Decay Heat Removal." The following major activities were observed or performed:

- outage planning meetings
- draining the RCS in preparation for reactor vessel head lift and set
- adequate reactor vessel level and temperature instrumentation during reduced inventory
- reactivity monitoring of shutdown plant conditions, including establishment of source range nuclear instrument channel check criteria monitoring and verification of nuclear instrument operability during core alterations
- fuel handling activities during core reload
- review of boron concentration sampling results, source range nuclear instrumentation system operability, containment closure capability, and refueling cavity water levels and clarity during fuel handling activities
- walkdowns of the RHR system during reduced inventory to verify decay heat removal capabilities
- verification of correct danger tag isolation boundaries and activities for the 1A06 safeguards bus and 1X03 high voltage auxiliary transformer maintenance activities
- walkdowns of emergency alternating current electrical power distribution systems during electrical maintenance
- walkdowns and inspection of 1A04 safeguards bus during preventative maintenance and cleaning activities
- walkdowns of the spent fuel pool cooling system after all nuclear fuel had been offloaded from the reactor to the spent fuel pool
- walkdowns of selected shutdown inventory addition makeup paths
- walkdowns of RCS boundary integrity prior to increasing reactor vessel inventory
- a review of the effect of switchyard maintenance activities on continuity of power to safeguards buses relied upon to maintain operability of RHR systems
- other general outage activities, including foreign material exclusion controls and safety shutdown assessments
- a review of the core reload safety evaluation data.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Conduct of a Partial G02 EDG SI Test Based on an Inadequate Assessment

a. Inspection Scope

During the week of September 2, 2002, the inspectors observed EDG G02 surveillance testing in accordance with Point Beach Test Procedure (PBTP) 121, "G02 EDG Auto Close Timing and Auto Close Permissive Testing," Revision 0, to determine the ability of G02 to satisfy TS surveillance requirement (SR) 3.8.1.5. The inspectors reviewed engineering evaluations 2002-0022, "Comparison of Shutdown versus Operating Risk for G02 ORT 3 Testing," Revisions 0 and 1, to evaluate the licensee's assessment of performing PBTP 121 with the both Units operating at full power. The inspectors also reviewed TS Bases section SR 3.8.1.5 and the NRC safety evaluation issued on August 29, 2002, concerning license Amendment No. 204 for Unit 1 and No. 209 for Unit 2 to understand the regulatory requirements associated with performing PBTP 121 in Mode 1. Finally, the inspectors reviewed completed PBTP 121 documentation to ensure that all surveillance criteria had been satisfied and G02 remained capable of fulfilling the intended safety function.

b. Findings

The inspectors identified a finding of very low safety significance (Green) concerning the conduct of a partial G02 EDG SI test while in Mode 1 based on an incomplete and inadequate assessment required by TS surveillance requirement 3.8.1.5.

Description

Point Beach Test Procedure 121, a safety-related, continuous-use procedure, was written to verify that the G02 (Unit 2, 'A' Train) EDG safeguards bus 2A05 Auto-Close timing and permissive circuits functioned properly. These permissive were normally verified during integrated SI tests conducted during refueling outages. In general, the test procedure included the abnormal sequence of fast-starting the EDG, opening the safeguards bus offsite transformer supply breaker, and then paralleling a running EDG with offsite power across the same transformer breaker.

Since the G02 EDG had not been not available for testing during the last U2R25 refueling outage, the licensee requested a TS Amendment to revise TS 3.8.1, "AC [Alternating Current] Sources - Operating," to allow portions of SR 3.8.1.5 to be performed with both Units in Mode 1, 2, 3, or 4 for the purposes of re-establishing operability. The NRC granted the TS amendment on August 29, 2002. A note in the revised SR 3.8.1.5 stated that portions of the integrated SI test could be performed during power operations to re-establish operability provided an assessment determined that the safety of the plant was maintained or enhanced. The revised TS Bases section 3.8.1.5 further amplified the intent of the requirement by stating that, "the assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in Modes 1, 2, 3, or 4."

On September 4, 2002, the inspectors reviewed engineering evaluation 2002-0022, Revision 0, and noted that the evaluation did not discuss the potential outcomes and transients associated with a failed partial surveillance; a successful partial surveillance; a perturbation of the offsite or onsite system when each was tied together or operated independently for the partial surveillance, or operator procedures available to cope with potential outcomes and transients. On the afternoon of September 4, the inspectors discussed these observations with members of the operations management, licensing, and risk assessment departments. As a result of the conversation, risk assessment engineers revised engineering evaluation 2002-0022 the same evening. Engineering evaluation 2002-0022, Revision 1, subsequently received risk assessment manager review and approval at approximately 8:30 on the morning of September 5.

At 8:45 a.m. on September 5, the Duty Shift Supervisor (DSS) gave permission, in Step 4.21 of PBTP 121, to prepare for the test, believing that the conditions required by the surveillance test were consistent with required plant conditions. Prior to Step 4.21, the Test Director had completed prerequisite Step 2.2 indicating that the performance of the test had been assessed per TS SR 3.8.1.5 Bases, and that it had been determined that plant safety had been maintained or enhanced. The inspectors interviewed the Test Director and verified that Step 2.2 had been completed based on the understandings of engineering evaluation 2002-0022, Revision 0. Additionally, the inspectors interviewed the DSS and noted that he had been unaware that Revision 1 to engineering evaluation 2002-0022 had been initiated or completed. The DSS stated that he had proceeded with the surveillance test on the basis of the information contained in engineering evaluation 2002-0022, Revision 0. The DSS stated that he had not known that a revision to the engineering evaluation had been initiated or completed.

At 9:28 a.m. in Step 5.2, the DSS gave permission to perform the surveillance test based on his understanding of engineering evaluation Revision 0 and his belief that all plant conditions had been met. Shortly after 9:36 a.m., the G02 EDG was fast-started in accordance with PBTP 121, Step 5.8. At approximately 9:45 a.m., a risk assessment engineer delivered Revision 1 of the engineering evaluation to the Test Engineer in the G02 EDG room. Upon receipt of Revision 1, the Test Engineer asked the risk assessment engineer if the conclusion of the risk evaluation had changed. The risk engineer responded that the conclusion had not changed. The Test Engineer asked the risk engineer to place a copy of Revision 1 of the engineering evaluation on his desk for review at a later time.

<u>Analysis</u>

Engineering evaluation 2002-0022, Revision 0, was incomplete and inadequate in that the evaluation did not address all the attributes required in SR 3.8.1.5. Specifically, Revision 0 did not discuss the potential outcomes and transients associated with a failed partial surveillance; a successful partial surveillance; a perturbation of the offsite or onsite system when each was tied together or operated independently for the partial surveillance, or operator procedures available to cope with the potential outcomes and transients. On the morning of September 5, 2002, the DSS and Test Director proceeded with PBTP 121 based on their understanding of engineering evaluation 2002-0022, Revision 0, an assessment required by TS SR 3.8.1.5 which was incomplete and inadequate.

The inspectors determined that the issue of conducting portions of an integrated SI test, based on an incomplete and inadequate assessment required by a TS surveillance requirement 3.8.1.5 was of more than minor significance since the test and assessment affected the availability, reliability, and capability of the G02 EDG, a mitigating system. The inspectors used Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," regarding mitigating systems and determined that the finding was not a design or qualification deficiency; did not represent an actual loss of the safety function for any mitigating system and did not result in a loss of function of a single train of any mitigating systems for greater than its TS allowed outage time; did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating events; and did not involve the loss of a safety function that contributed to external event initiated core damage accident sequences. Therefore, the finding screened as Green and was of very low safety significance.

Enforcement

The inspectors attended the pre-job briefing for the licensed operators and test engineering personnel prior to conducting PBTP 121. The inspectors noted that the test sequence was relatively simple and the briefing had been of high quality and comprehensive in terms of discussing abnormal operating procedures and unexpected plant conditions. Thus, while the assessment relied upon by the licensed operators and test director to perform the partial integrated SI test in engineering evaluation 2002-0022, Revision 0, was incomplete and inadequate, the simplicity of the test and quality of the briefing effectively met the requirements of TS Surveillance Requirement 3.8.1.5. Thus, no violation of regulatory requirements occurred. Nonetheless, conducting portions of an integrated SI test without all licensed operators and test personnel having a clear understanding of a complete and comprehensive assessment was considered a finding (FIN 50-301/02-10-03) This finding was entered into the licensee's corrective action system as CAP029498, "PBTP-121 G-02 EDG Modified ORT-3 Test Risk Assessment May Have Been Insufficient."

.2 EDG G04 Calibration Procedure

a. Inspection Scope

During the week of July 22, 2002, the inspectors observed EDG G04 instrumentation calibration performed in accordance with ICP 13.007B-2, "Emergency Diesel Generator G04 Calibration Procedure," Revision 4, to determine the ability of G04 instrumentation to monitor operation within design parameters. The inspectors observed the calibration methods and equipment as well as the interface between test, instrument and control, and mechanical maintenance personnel.

b. Findings

No findings of significance were identified.

.3 SI Pump Recirculation Valve Interlock Testing with Containment Sump Recirculation Valves

a. Inspection Scope

During the week of September 9, 2002, the inspectors reviewed the results of IT-45, “Safety Injection Valves (Quarterly) - Unit 2,” Revision 43, performed on June 13, 2002, to understand the circumstances associated with the failure of the 2SI-987B YNV relay. The inspectors reviewed design basis requirements associated with preventing the release of radionuclides to the environment when switching from the injection to the recirculation phase of cooling during a design basis event. The inspectors reviewed the electrical circuitry and interlocks between valves 2SI-897A/B, “Safety Injection Test Line Return,” and 2SI-859A/B, “RHR Pump Suction From Containment,” to determine which portions of the original safeguards circuitry were checked during routine surveillance testing. The inspectors also reviewed emergency operating procedures for transferring to sump recirculation during design basis events to ensure that no radionuclide containment bypass paths existed. Finally, the inspectors reviewed CAP028619, “SI-897/851 Interlock Testing Methodology,” which was initiated as a result of this inspection activity and discussed the inclusion of the SI-897/851 interlocks as part of Generic Letter 96-01 testing requirements.

b. Findings

No findings of significance were identified.

.4 Unit 1, Train 'B' Engineered Safety Features (ESF) System Logic Test

a. Inspection Scope

During the week of July 22, 2002, the inspectors reviewed the results of the monthly, staggered surveillance test of the Unit 1, ESF Train ‘B’ logic channel relays. The review was conducted to verify that test data were complete, verified, and met procedure requirements; test frequency was adequate to demonstrate operability and reliability; and that for test results that did not meet the acceptance requirements, results of engineering evaluations, root cause analyses, and bases for returning to operable status were acceptable.

b. Findings

No findings of significance were identified.

.5 Unit 2 Power Range Detector Power Level Adjustments During Load Swing

a. Inspection Scope

During the week of August 26, 2002, the inspectors reviewed the results of TS surveillance 0-TS-RE-002, “Power Range Detector Power Level Adjustment,” Revision 4, and CAP029052, “N41 High Flux Trip Greater Than TS Limit After Low Power Gain Adjustments,” to determine whether Unit 2 had been operated during a July 27 and 28, 2002, load swing such that the power range nuclear instrument high flux trip would not have functioned as designed. The inspectors reviewed completed 0-TS-RE-002 surveillance results for power level adjustments made before and after the return to full power; interviewed the reactor engineering manager; reviewed plant computer and calorimetric indications of reactor power, and reviewed the associated apparent cause evaluation to determine whether a high flux trip signal would have occurred at the TS required setpoint of 108 percent of rated thermal power.

b. Findings

No findings of significance were identified.

.6 Unit 1, Train 'A' and ‘B’ Engineered Safety Features System and Reactor Protection System Logic Test

a. Inspection Scope

During the week of August 12, 2002, the inspectors observed the test and reviewed the results of the monthly, staggered surveillance test of the Unit 1, ESF and reactor protection system Train ‘A’ and Train ‘B’ logic channel relays. The inspectors observed personnel safety precautions, compliance with the procedure prerequisites, proper communications during testing, completion of all applicable procedure steps, and verification of test results prior to returning the equipment to service. A review was conducted to verify that test data were complete, verified, and met procedure requirements.

b. Findings

No findings of significance were identified.

.7 Unit 1, ‘B’ Train Integrated SI Test

a. Inspection Scope

During the week of September 16, 2002, the inspectors observed integrated SI system testing in accordance with operations refueling test ORT 3B, “Safety Injection Actuation With Loss of Engineered Safeguards AC Power (Train B) Unit 1,” to determine the ability of Unit 1 safety-related equipment to respond to a design basis accident. The inspectors reviewed pre-test equipment alignments and plant conditions prior to starting the test to verify proper system configurations. The inspectors observed emergency core cooling system load sequencing, shedding, and restoration from the control room to verify that Unit 1, 'B' train emergency core cooling system equipment was capable of performing the intended design function. Communication practices, control room decorum, receipt of expected alarms and warning lights, supervisory control, procedure adherence, and the interface between test and on-shift licensed personnel were observed. The inspectors reviewed the completed test documentation to verify that all equipment acceptance criteria had been met and all equipment remained capable of performing the intended safety function.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

.1 Temporary Air Filtration and Cooling System Installed In Support of Control Room Envelope Upgrade Modifications

a. Inspection Scope

During the weeks of July 8 and 15, 2002, the inspectors reviewed several WOs, design CLs, and safety evaluation screenings to verify that the temporary control room filtration and cooling system modification was properly installed, had no effect on the operability of the safety-related equipment, and met design basis requirements. The inspectors also conducted temporary system walkdowns to verify proper system operation and continuity of power in the event of a loss of offsite power or station blackout. The inspectors examined the high-energy-line-break, fire, and security penetrations made by the temporary cooling system into the control room envelope to verify that the integrity of the control room boundary was maintained. The inspectors also considered the affect of the weight loading of the temporary cooling system on the portion of the turbine deck located to the east of the control room envelope to ensure that the ceiling of rooms containing vital equipment would remain intact during seismic events. The inspectors compared the combined heat load of the control and computer rooms with the heat removal capacity of the temporary cooling system to ensure that control room ambient temperature design requirements would continue to be met while the temporary system was installed. The inspectors also reviewed temporary filtration system testing results to ensure that the system was capable of maintaining a positive pressure in the control room envelope relative to adjacent areas. The inspectors reviewed temporary filtration system operating instructions to ensure adequate auxiliary operator guidance existed for system operation. Finally, the inspectors reviewed CAP028769, “Regulator Review of MR 97-049*E, Control Room Envelope Upgrades,” which was initiated as a result of this inspection activity.

b. Findings

No findings of significance were identified.

.2 Sodium Hypochlorite Temporary Supply

a. Inspection Scope

During the week of July 29, 2002, the inspectors reviewed temporary modification 02-035, “Sodium Hypochlorite Temporary Supply,” to verify that the modification was properly installed and had no effect on the operability of the safety-related equipment. The inspectors selected the temporary sodium hypochlorite supply to ensure that biofouling control of the circulating and SW systems was maintained during replacement of the normal sodium hypochlorite tank, T-131, which had unexpectedly leaked on July 19 requiring a full offload of the tank's contents. The inspectors performed walkdowns of the temporary system and verified that the system included controls to prevent an inadvertent spill of sodium hypochlorite solution to the environment. Finally, the inspectors reviewed Temporary Procedure Changes 2002-0472, “Chlorination of Circulating Water Pump Suction Well(s) and Service Water in Automatic Mode,” and 2002-0473, “Chlorination of Service Water in Manual Mode,” to ensure that temporary system operating instructions had been properly translated into existing plant procedures.

b. Findings

No findings of significance were identified.

Emergency Preparedness

EP6 Drill Evaluation (71114.06)

.1 Resident Inspector Observation of Emergency Preparedness Drill, August 1, 2002

a. Inspection Scope

On August 1, 2002, the resident inspectors observed an emergency preparedness drill to evaluate the adequacy of the licensee’s drill conduct and critique performance. The inspectors observed the drill from the control room (simulator), technical support center (TSC), and the emergency operating facility (EOF) to evaluate emergency preparedness performance at multiple locations. The inspectors also attended control room and TSC critique sessions immediately following the drill termination on August 1, to evaluate the licensee’s ability to identify weaknesses and deficiencies. The inspectors’s reviewed Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2, Section 2.4, “Emergency Preparedness Cornerstone,” to aid in determining the adequacy of the licensee’s critique process and whether certain NRC Drill/Exercise Performance (DEP) opportunities should have been considered successful. Human performance aspects of the August 1, emergency planning drill and the quality of the critique are discussed further in Section 4AO2.1 of this report.

b. Findings

The inspectors identified a URI concerning the critique of an Alert declaration and Site Area Emergency notification for the August 1, 2002, emergency preparedness drill.

Description

The drill was conducted on Unit 1 and commenced with the Unit already in an Unusual Event classification due to high RCS activity. Reactor coolant system activity was then increased until an Alert was declared due to loss of one fission product barrier (fuel cladding). The cladding failure was indicated by increasing radiation levels on a post-accident sample line radiation monitor intended to monitor primary coolant sample activity, RE-109. The Alert was expected to be declared when RE-109 exceeded 600 mr/hr. Increasing reactor coolant pump vibrations then caused the operators to decrease reactor power and manually trip the reactor. Approximately 40 minutes after the reactor trip, 'B' steam generator code safety valve failed open causing the loss of a second fission product barrier (primary containment). The licensee was expected to have declared a Site Area Emergency based on the loss of two fission product barriers (fuel cladding and containment). Approximately one hour after the steam generator safety lifted, a steam generator tube rupture occurred in the same generator leading to a loss of three fission product barriers (fuel cladding, RCS, and primary containment) and a General Emergency declaration.

Shortly after the drill began at 7:30 a.m., a malfunction was inserted into the simulator to increase RCS activity to 12 microcuries/cubic centimeter (uCi/cc), an activity level which would cause RE-109 to exceed 600 mr/hr. The simulator modeled the transit time of the increase of RCS activity to the RE-109 radiation monitor with a time delay of 9 minutes. At 7:35 a.m., the control room received a Radiation Monitoring System (RMS) master alarm and requested a radiation protection (RP) technician report to the control room to monitor RMS trends. The RP technician reported to the control room and began monitoring the RE-109 activity trends using the 10-Minute Average display. Two other RE-109 data display options were available to the RP technician; Current and 1-Minute Average. At 8:07 a.m. the RP technician shifted from the 10-Minute Averaging display to the 1-Minute Averaging display and immediately noted that radiation levels indicated 1060 mr/hr. The RP technician informed the Duty Shift Supervisor and an Alert declaration was made at 8:07 a.m.

Based on a review of controller logs, participant logs, and direct simulator booth and control room floor observations, the inspectors noted that RE-109 exceeded the 600 mr/hr Alert declaration threshold at a time bounded between 7:35 a.m. and 7:44 a.m. Since the RP technician had chosen to monitor RE-109 trends using the 10-Minute Average display, however, the ability to detect increasing RCS activity trends in a timely manner was restricted. The inspectors estimated that the failure to use the Current or 1-Minute Average RE-109 display options resulted in a delay of between 23 and 32 minutes to declare the Alert. In reviewing the licensee's August 1, Drill and Exercise Manual, Section 4.5, "NRC Performance Indicator Data," the inspectors noted that the licensee had pre-designated the Alert declaration as a DEP performance indicator (PI) opportunity. The inspectors reviewed the licensee's completed Section 4.5 form on August 22 and noted that the licensee had considered the Alert declaration a successful PI opportunity.

The inspectors compared the licensee's Alert declaration conclusions against the guidance found in NEI 99-02, Revision 2, Section 2.4, "Emergency Preparedness Cornerstone, Definition of Terms," Lines 29 and 30, which stated that timely, "classifications are made consistent with the goal of 15 minutes once available plant parameters reach an Emergency Action Level (EAL)." Since using the 10-Minute Average RE-109 display resulted in a delay of between 23 and 32 minutes to declare an Alert once radiation levels had exceeded 600 mr/hr, the inspectors disagreed with the licensee's conclusion that the Alert declaration had been made in a timely fashion and represented a successful NRC PI opportunity.

Likewise, the inspectors disagreed with the licensee's conclusion that the Site Area Emergency notification had been made in a accurate manner. NEI 99-02, Revision 2, Section 2.4, "Emergency Preparedness Cornerstone, Definition of Terms", Page 85, Lines 5 thru 8," stated that accuracy included the initial notification form description of the emergency. The licensee declared a Site Area Emergency (SAE) at 9:36 a.m. based on degradation of two fission product barriers (fuel cladding and the RCS). The SAE notification form completed at 9:44 a.m. specifically stated that the classification was based on indications of an RCS leak greater than 100 GPM. In actuality, the licensee had mis-diagnosed plant conditions and made an error in not recognizing that the 'B' steam generator code safety valve had failed open. The licensee confused a 100 GPM charging rate (an attempt by the pressurizer level control system to restore pressurizer level to the programmed band as a result of the steam generator code safety failing open and the resultant RCS temperature decrease) with an indication of an RCS leak. Thus, at the time of the SAE declaration at 9:36 a.m., the licensee had not fully recognized which two fission product barriers were degraded (fuel cladding and primary containment). While the SAE was the correct emergency class, the SAE declared at 9:36 a.m. was based on the wrong two degraded fission product barriers and represented a significant mis-diagnosis of plant conditions. The SAE notification form completed at 9:44 a.m. was transmitted to State, Local, and NRC authorities. The inspectors disagreed with the licensee's conclusion that the SAE declaration was made in an accurate manner and represented a successful NRC PI opportunity.

Enforcement

The safety significance of the quality of the critique of the August 1, 2002, emergency preparedness drill relative to the Alert declaration and Site Area Emergency notification is To Be Determined and the issue will be considered a URI pending further regulatory review by Regional Emergency Preparedness staff (URI 50-266/02-10-04; 50-301/02-10-04). The issue did not represent an immediate safety concern.

3 SAFEGUARDS

Cornerstone: Physical Protection

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

The Office of Homeland Security (OHS) developed a Homeland Security Advisory System (HSAS) to disseminate information regarding the risk of terrorist attacks. The

HSAS implements five color-coded threat conditions with a description of corresponding actions at each level. NRC Regulatory Information Summary (RIS) 2002-12a, dated August 19, 2002, "NRC Threat Advisory and Protective Measures System," discusses the HSAS and provides additional information on protective measures to licensees.

On September 10, 2002, the NRC issued a Safeguards Advisory to reactor licensees to implement the protective measures described in RIS 2002-12a in response to the Federal government's declaration of threat level "orange." Subsequently, on September 24, 2002, the OHS downgraded the national security threat condition to "yellow" and a corresponding reduction in the risk of a terrorist threat.

The inspectors interviewed licensee personnel and security staff, observed the conduct of security operations, and assessed licensee implementation of the threat level "orange" protective measures. Inspection results were communicated to the region and headquarters security staff for further evaluation.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 RCS Leakage PI

a. Inspection Scope

During the week of August 19, the inspectors reviewed 2001 and 2002 data for the RCS Leakage PI for Units 1 and 2 using the definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2. The inspectors reviewed operations department data and nuclear plant procedure NP 5.2.16 - Attachment C, "NRC Performance Indicators - RCS Identified Leak Rate", July 2001 to June 2002, to verify that the maximum monthly value of identified leakage had been reported as required by NEI 99-02.

b. Findings

No findings of significance were identified.

.2 Safety System Functional Failures PI

a. Inspection Scope

During the week of September 16, the inspectors reviewed data for the 3rd and 4th quarters of 2001 and the 1st and 2nd quarters of 2002 for the Units 1 and 2 Safety System

Functional Failures PIs. The inspectors used LERs and other station documents, and the definitions and guidance contained in NEI 99-02 for this review.

b. Findings

No findings of significance were identified.

.3 AFW System PI

a. Inspection Scope

During the week of September 23, the inspectors reviewed data for the 3rd and 4th quarters of 2001 and the 1st and 2nd quarters of 2002 for the Heat Removal System Unavailability (AFW) PI. The inspectors used station logs, condition reports, and other station documents, and the definitions and guidance contained in NEI 99-02 for this review.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Human Performance and Licensee Critique of Emergency Planning Drill Conducted on August 1, 2002

a. Inspection Scope

The inspectors reviewed licensee performance during an August 1, emergency preparedness drill and evaluated the ability of the licensee to self-critique drill performance weaknesses and deficiencies. The inspectors observed the drill from the control room (simulator), TSC, and EOF. The inspectors reviewed drill controller, observer, and participant logs to determine when specific accident conditions became available to the drill participants and when specific plant conditions were diagnosed. The inspectors also attended control room and TSC critique sessions immediately following the drill termination on August 1, to evaluate the licensee's ability to identify weaknesses and deficiencies.

b. Issues

Alert Declaration Timeliness

As discussed in emergency preparedness section EP 6.1 of this report, failure of an RP technician to utilize either the Current or One-Minute display options for RE-109 radiation levels resulted in a delay of between 23 and 32 minutes to declare an Alert once radiation levels had exceeded the emergency action level criteria of 600 mr/hr. During the control room (simulator) critique session immediately following the drill termination on August 1, the inspectors noted that the DSS stated that he thought the crew's timing of the Alert declaration had been appropriate. The DSS based his comment on when the RP technician, using the 10-Minute Averaging display, had informed him of RE-109 radiation levels exceeding 600 mr/hr. No mention of the RP technician providing untimely RE-109 radiation level trends was made during the critique. Specifically, the aspect of using the Current or 1-Minute RE-109 Average displays from the onset of monitoring so as to have decreased the time to notice radiation levels exceeding 600 mr/hr was not discussed.

Additionally, a drill controller's chronological event log estimated that, at 7:44 a.m., radiation levels had exceeded 600 mr/hr. Although available to the emergency preparedness staff during and following the drill critiques, this data point was not mentioned as indicative of a delay in declaring the Alert. As documented in the licensee's "Performance Indicator Evaluation Form for Emergency Classification, Notification, and Protective Action Recommendation Opportunities," form completed on August 2, the Alert declaration was considered a timely and successful DEP performance indicator. Finally, the licensee's review of the drill critique did not mention the RP technician's monitoring of the RE-109 radiation monitor as an area for improvement and no corrective action documents were written as a result of the RP technician's, control room crew's, or emergency response organization's timeliness in making the Alert declaration. The inspectors noted that following a meeting with the members of the emergency preparedness staff on August 26, to discuss the Alert declaration timeliness, CAP029147, "August 1 Drill Declaration of Alert May Not Have Met The 15 Minute Goal," was written by the licensee.

Site Area Emergency Declaration Accuracy

Section EP 6.1 of this report also discussed the accuracy of declaring a SAE based on the misdiagnosed conditions of degraded fuel cladding and RCS barriers when actual plant conditions indicated degradation of the cladding and primary containment barriers. During the critique of the SAE, the licensee documented in CAP028952, "August 1 Drill EAL for Site Emergency," the inconsistent understanding of the loss of the second barrier that led to the SAE classification. The CAP discussed the emergency response organizations identification that there was a faulted steam generator and confusion that if an RCS leak had occurred, it had been isolated when letdown was secured. The CAP also identified that in the additional information section of the nuclear accident reporting form, the RCS had been identified as the second degraded fission product barrier. The CAP documented the licensee's rationale of not preparing a new notification form since there had been no change in the classification or emergency action level. The CAP also asked the question of whether the event notification had been accurate based on the information available when it was made. The CAP did not address the question of whether the SAE notification, based on accuracy, should be considered a successful NRC Drill and Exercise Performance Indicator opportunity.

General Emergency Classification

A steam generator tube rupture signal was inserted into the control room simulator at 10:25 a.m. and increased to 200 GPM over 300 seconds. Thus, by 10:30 a.m. the tube rupture signal was fully inserted into the control room simulator. The licensee declared a

General Emergency at 10:37 a.m. based on an offsite field survey team report of 10 mrem/hr dose rates one mile west of the plant. The dose rate provided clear indication that all three fission product barriers had been compromised. Although not an unsuccessful performance indicator opportunity, the inspectors noted that before the drill was terminated, the NRC had not been informed of the pathway by which the third fission product barrier had failed. The inspectors noted that no corrective action documents were written discussing the lack of communications to the NRC indicating that a steam generator tube rupture was the failure that had allowed fission products to be released to the environment.

.2 Untimely Follow-Up of Corrective Actions Identified by CAP028877 for 2AF-114

a. Inspection Scope

During the week of July 29 and September 4, 2002, the inspectors reviewed CAP 028877,"Linear Indication Found On Valve 2AF-114," to evaluate the adequacy and timeliness of licensee corrective actions associated with a linear indication identified on the valve body of 2AF-114, a Unit 2 turbine-driven AFW pump mini-recirculation check valve. The inspectors also reviewed CAP029201 to ensure extent-of-condition review timeliness deficiencies were entered into the corrective action program. Inspector review of the operability determination associated with CAP028877 is provided in Section 1R15.4 of this report.

b. Issues

Corrective action program document CAP028877 indicated that there was a small crack on the surface of the 2AF-114 valve body. The crack was ground out and minimum wall thickness was verified in accordance with Table 30 of USAS B16.5. The inspectors agreed with the licensee assessment that the linear crack in the valve body may have been present since the valve was installed in 1990. When the crack was ground out, an oxide layer was revealed indicating that the flaw was related to original manufacture. In addition, there were indications that there had been some attempt to remove the crack in the past.

The inspectors reviewed WO 9914184 that led to the writing of the CAP and noted that weld #5 had failed the dye penetrant (PT) portion of the inspection. The inspectors asked the licensee to provide the documentation that indicated that weld #5 had successfully passed a PT examination prior to the closure of the package. The licensee discovered that there was no documentation and initiated an apparent cause evaluation (ACE) to investigate how the WO could have been reviewed by eight personnel and still have been closed with no PT re-examination required. The results of the ACE were that the work plan had allowed several tests to be performed for each signature in the procedure, a practice that led to an inadequate review.

The CAP recommended that the extent of condition of similar valve body defects needed to be evaluated. Fifty-four valves of similar manufacture were identified in safety related systems at Point Beach. The licensee wrote three WOs to evaluate a representative sample of 30 similar valves with the intention that, if more problems were found, the evaluation population would be increased. It took the licensee until the last week of

August, a period of 4 weeks, to have a plan developed to inspect similar valves in the plant. The program was implemented, but not completed, at the end of this report period.

In reviewing the ACE, the inspectors noted that there was no 2AF-114 operability determination from the time of the initial work (during the Unit 2 outage) until the system was declared inoperable on July 29, 2002. The inspectors provided this comment to the licensee, noting that it was the second time that operability questions had been raised by the inspectors. The licensee agreed that an operability determination should be written for the uncovered period and added the information to the ACE.

.3 Development of (a)(1) Maintenance Rule Action Plan for G05 GT System

a. Inspection Scope

During the week of September 16, 2002, the inspectors reviewed licensee corrective actions associated with CAP001899, "GT System Meets Criteria for (a)(1) Status," to evaluate the adequacy and timeliness of corrective actions associated with elevating the G05 GT from (a)(2) to (a)(1) status on January 17. Inspector review of the maintenance rule aspects of the G05 GT system are provided in Section 1R12.1 of this report.

b. Issues

The licensee elevated the G05 GT from a(2) to (a)(1) status on January 17, 2002, when a system engineer determined that earlier G500 starting diesel failures met the definition of repetitive maintenance preventable functional failures. The system engineer initiated CAP001899, "GT System Meets Criteria for (a)(1) Status," to document the transition to (a)(1) status and to track the subsequent corrective actions.

Corrective action item CA003554 was assigned to the GT system engineer on January 18, to prepare an action plan to return the GT system to a(2) status. A due date of March 15, was originally assigned but was extended to April 16 to allow inclusion of the March 2002 G500 failure into the (a)(1) action plan. On April 24, the system engineer requested another due date extension to the (a)(1) action plan to allow input by the facilities general supervisor. The system engineer's supervisor approved the second extension request on May 14, stating that the second extension was necessary to allow support of other higher priority work associated with the troubleshooting and repair of the G02 (Unit 2, 'A' train) EDG. The GT system engineer subsequently completed the draft (a)(1) action plan on July 15, and action item CA003554 was closed on July 16. Revision 0 of the (a)(1) action plan was submitted to the maintenance rule expert panel on August 5. Initial comments were incorporated and the (a)(1) action plan was again discussed during an expert panel meeting on September 12. The (a)(1) action plan received final expert panel approval on September 13, a period of 7 months and 27 days after the GT system was first declared (a)(1).

4OA3 Event Follow-up (71153)

.1 (Open) Licensee Event Report (LER) 301/2002-002-00: Pressurizer safety valve failed to lift at test pressure.

Finding

This LER discussed the self-revealing discovery during off-site testing that a Unit 2 pressurizer safety valve would not have lifted at the TS-required lift setting of $\geq$2410 psig and $\leq$2560 psig. The result was Point Beach Unit 2 having operated with one inoperable pressurizer safety valve for the past operating cycle, December 2000 to April 2002.

Description

On April 24, 2002, a vendor (Crane Nuclear) conducting testing of Unit 2 RCS pressurizer safety valves reported that safety valve 2RC-435 (SN N82732-00-0001) failed to lift at test pressures up to 2660 psig. The lift pressure specification for this valve was from 2440 to 2551 psig. The vendor's investigation revealed that the valve from position 2RC-435 had last been tested in November 2000. During the November 2000 test, the valve setpoint was determined to be within specification. In accordance with the vendor's normal practice, however, the valve was then checked for post-setpoint testing seat leakage. Since the valve was identified to have some seat leakage, a jack-and-lap procedure was performed to lap the valve disc and nozzle. During the reassembly of the valve following the November 2000 lapping, a technician failed to ensure that the spindle and disc holder were fully engaged, leaving the spindle threads engaged in the disc holder threads. This error caused the actual lift setpoint of the safety valve to exceed the allowable limits. The valve manufacturer estimated that the actual lift point of the mis-assembled safety valve would have exceeded 3,000 psig, rendering the valve incapable of performing the intended safety function during the past operating cycle.

Analysis

The RCS is protected against overpressure by two safety valves located on the top of the pressurizer. The safety valves are Crosby Model HB-86-BP E with relief capacities of 288,000 pounds mass per hour (lbsm/hr) each for a total capacity of 576,000 lbsm/hr. The design capacity is based on RCS pressure not exceeding 110 percent of design pressure for the maximum calculated insurge of reactor coolant into the pressurizer. The design basis event that most challenges the RCS boundary due to pressure is the Loss of External Load Event. The Loss of External Load Event assumes an instantaneous loss of turbine-generator load with no immediate reactor trip and with no atmospheric or condenser steam dumps. The event also assumes continued main feedwater flow with no credit taken for primary and secondary power-operated relief valves (PORVs), pressurizer level control, and pressurizer spray.

For the Loss of External Load Event using an up-rated core power of 1650 Megawatts thermal and two pressurizer safety valves, the calculated peak RCS pressure was found to be less than the TS safety limit of 2735 psig. However, with one safety valve inoperable, the RCS pressure would exceed the 2735 psig safety limit. Nonetheless, the licensee reviewed the availability of the two pressurizer PORVs and concluded that they had been available throughout the last Unit 2 operating cycle. With a relief capacity of each primary PORV of 179,000 lbsm/hr, the licensee determined that the PORVs would have more than compensated for the 288,000 lbsm/hr relief capacity of the inoperable pressurizer safety valve. The licensee used the availability of the pressurizer PORVs to conclude that the RCS TS safety limit of 2735 psig would not have been exceeded following a Loss of External Load Event during the last Unit 2 operating cycle.

Additionally, while performing a risk analysis of this event, the licensee considered the dependency of the pressurizer PORVs on instrument air and the possible loss of instrument air due to a SI/containment isolation signal. To meet the Anticipated-Transient-Without-Scram (ATWS) rule, Point Beach depended on a generic vendor analysis which credited both the pressurizer safety valves and PORVs to limit the RCS pressure response to within design limits. During the first part of an ATWS event, a large amount of inventory would be released into containment from the pressurizer PORVs and safety valves. This fluid release would exceed the capacity of the pressurizer relief tank; fail the tank's rupture disk; cause a rise in containment pressure, and isolate instrument air when the SI containment isolation setpoint was reached. Since the pressurizer PORVs depend on instrument air for operation, the PORVs would fail closed soon after the containment isolation signal occurred. The ATWS analysis demonstrated that the peak RCS pressure would occur within the first 250 seconds of the transient. If the pressurizer PORVs were to close prior to this time, the peak pressure may be above that considered in the generic analysis. The licensee contracted with a vendor to determine the impact of the loss of instrument air to the PORVs on containment pressure response. The results of this evaluation were expected in October 2002.

The issue of having an inoperable safety valve installed on the Unit 2 RCS for an entire operating cycle was more than minor and was characterized as being of at least very low safety significance (Green) since the issue affected the functionality of the RCS pressure boundary, a physical barrier designed to protect the public from radionuclide releases caused by accidents or events.

Enforcement

Technical Specification Section 3.4.10, "RCS Pressurizer Safety Valves," requires that two pressurizer safety valves be operable with lift settings $\geq$2410 psig and $\leq$2560 psig in Modes 1, 2, 3, and portions of Mode 4. Contrary to the above, Unit 2 operated in Mode 1 from December 2000 to April 2002 with a safety valve (SN N82732-00-0001) in position 2RC-435 such that the valve would not have lifted at the required setting.

The violation did not represent an immediate safety concern since Unit 2 was shutdown in a refueling outage when the inoperable safety valve was identified and operable safety valves with acceptable lift setpoints were installed prior to startup. Since an analysis is required to determine the risk significance of the violation and the licensee's ability to have met licensing basis, design basis, and ATWS rule requirements, the safety significance of the issue is To Be Determined. The issue will be considered a URI pending regulatory review of the licensee's containment and RCS pressure response results (URI 50-301/02-10-05).

4OA4 Cross-Cutting Findings

.1 A finding described in Section 1R12.1 of this report had, as its primary cause, a human performance deficiency, in that, the appropriate resources were not assigned to the G05 GT once the system had been placed in the 10 CFR 50.65(a)(1) monitoring program on January 17, 2002. The result was a nearly eight month delay in approving the (a)(1) action plan and setting performance goals such that the G05 GT could be returned to (a)(2) status.

.2 A finding described in Section 1R20.1 of this report had, as its primary cause, a human performance deficiency, in that, engineering personnel failed to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions. Specifically, safety-related shutdown emergency procedures contained operator instructions that could have caused the top of the steam generator U-tubes to become uncovered, thereby affecting the ability of the steam generators to function as a heat sink for removing reactor decay heat.

.3 A finding described in Section 1R22.1 of this report had, as its primary cause, a human performance deficiency, in that, licensed operators, test personnel, and probabilistic risk assessment personnel failed to communicate the existence or status of a revised assessment required by TS surveillance requirement 3.8.1.5. As a result, a portion of an integrated SI test on the G02 EDG while in Mode 1 was conducted based on an incomplete and inadequate assessment.

4OA5 Other

.1 Circumferential Cracking of Unit 1 Reactor Pressure Vessel Head Penetration Nozzles (Temporary Instruction 2515/145)

a. Inspection Scope

The inspectors performed a review of the licensee’s activities in response to NRC Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” to verify compliance with applicable regulatory requirements. In accordance with the Bulletin, Point Beach Nuclear Plant Unit 1 was characterized as belonging to the sub-population of plants with greater than 12 effective degradation years for assessing the potential for reactor pressure vessel head and vessel head penetration nozzle cracking. As a result, Point Beach responded to the Bulletin by performing a direct visual examination of the upperside of the reactor vessel head; an ultrasonic test of the control rod drive mechanism base material; and limited dye penetrant testing of J-groove weld material. To assess the licensee’s efforts in conducting visual, ultrasonic, and surface examinations of the Unit 1 reactor vessel head, the inspectors;

- interviewed inspection personnel
- reviewed procedures and inspection reports, including final data sheets and video tape documentation for selected ultrasonic, dye penetrant, and visual examinations
- reviewed raw ultrasonic data on the data analysis station with the assistance of the vendor’s Level III senior analyst
- reviewed selected demonstration and qualification reports
- reviewed the licensee’s 30-day response to NRC Bulletin 2002-02

- reviewed portions of a vendor’s reactor vessel design specification details
- reviewed portions of a vendor’s structural integrity evaluation for reactor vessel head penetrations
- reviewed 1994 eddy current data results on selected CRDMs.

Due to the ongoing U1R27 refueling outage, this inspection activity was not completed by end of the inspection period. Completion of the inspectors’ review of Unit 1 reactor pressure vessel head and vessel head penetration nozzle cracking will be documented in the next integrated inspection report.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting

The resident inspectors presented the routine inspection results to Mr. A. Cayia and other members of licensee management at the conclusion of the inspection on October 2, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

KEY POINTS OF CONTACT

Licensee

J. Anderson, Production Planning Group Manager
L. Armstrong, Design Engineering Manager
J. Boesch, Maintenance Manager
A. Cayia, Site Vice-President
F. Flentje, Senior Regulatory Compliance Specialist
D. Gehrke, Nuclear Oversight Supervisor
N. Hoefert, Engineering Programs Manager
R. Hopkins, Nuclear Oversight Supervisor
C. Krause, Regulatory Compliance
D. Schoon, Operations Manager
C. Sizemore, Training Supervisor
P. Smith, Operations Training Supervisor
J. Strharsky, Assistant Operations Manager
T. Taylor, Plant Manager
S. Thomas, Radiation Protection Manager
R. Turner, Inservice Inspection Coordinator
T. Webb, Licensing Manager

Nuclear Regulatory Commission

D. Spaulding, Point Beach Project Manager, NRR
R. Lanksbury, Chief, Reactor Projects Branch 5
J. Dyer, Region III Regional Administrator

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-266/02-10-01; 50-301/02-10-01	NCV	Untimely Development and Approval of (a)(1) Action Plan for Gas Turbine, G05 (Section 1R12.1)
50-301/02-10-02	NCV	Use of Steam Generator Narrow Range Level Detector During Cold Shutdown Plant Conditions (Section 1R20.1)
50-301/02-10-03	FIN	Conduct of a Partial G02 EDG Safety Injection Test Based on an Inadequate Assessment (Section 1R22.1)
50-266/02-10-04; 50-301/02-10-04	URI	Observation and Review of Emergency Preparedness Drill, August 1, 2002 (Section EP6.1)
50-301/2002-002-00	LER	Pressurizer Safety Valve Failed To Lift At Test Pressure (Section 4OA3.1)

50-301/2002-010-05	URI	Inoperable Unit 2 Reactor Coolant System Safety Valve for Entire 18 Month Operating Cycle, December 2000 to April 2002 (Section 4OA3.1)

Closed

50-266/02-10-01; 50-301/02-10-01	NCV	Untimely Development and Approval of (a)(1) Action Plan for Gas Turbine, G05
50-301/02-10-02	NCV	Use of Steam Generator Narrow Range Level Detector During Cold Shutdown Plant Conditions
50-301/02-10-03	FIN	Conduct of a Partial G02 EDG Safety Injection Test Based on an Inadequate Assessment
50-301/02-06-01	URI	Use of Steam Generator Narrow Range Level Detector During Cold Shutdown Plant Conditions

Discussed

None

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
AFW	Auxiliary Feedwater
ATWS	Anticipated-Transient-Without-Scram
CA	Corrective Action
CAP	Corrective Action Program
CCHX	Component Cooling Water Heat Exchanger
CCW	Component Cooling Water
CE	Condition Evaluation
CFR	Code of Federal Regulations
CL	Checklist
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DBD	Design Basis Document
DEP	Drill/Exercise Performance
DSS	Duty Shift Supervisor
EDG	Emergency Diesel Generator
EOF	Emergency Operating Facility
EOP	Emergency Operating Procedure
ESF	Engineered Safety Features
FSAR	Final Safety Analysis Report
GPM	Gallons Per Minute
GT	Gas Turbine
HSAS	Homeland Security Advisory System
IT	Inservice Test
LBSM/HR	Pounds Mass Per Hour
LER	Licensee Event Report
MPFF	Maintenance Preventable Functional Failure
MRR	Metering, Relaying, and Regulation
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NPP	Nuclear Plant Procedure
NRC	Nuclear Regulatory Commission
OI	Operating Instruction
OP	Operations Procedure
ORT	Operations Refueling Test
OHS	Office of Homeland Security
P&ID	Piping and Instrumentation Diagram
PBF	Point Beach Form
PBNP	Point Beach Nuclear Plant
PBTP	Point Beach Testing Procedure
PC	Periodic Check
PI	Performance Indicator
PMT	Post-Maintenance Testing
PORV	Power-Operated Relief Valve
PT	Dye Penetrant
RCS	Reactor Coolant System

RHR	Residual Heat Removal
RIS	Regulatory Issues Summary
RMP	Routine Maintenance Procedure
RMS	Radiation Monitoring System
RP	Radiation Protection
RWST	Refueling Water Storage Tank
SAE	Site Area Emergency
SI	Safety Injection
SR	Surveillance Requirement
SW	Service Water
TS	Technical Specification
TSC	Technical Support Center
URI	Unresolved Item
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Periodic Check (PC) 43 Part 2	Switch and Breaker Alignment Checks	Revision 33
M209 Sheet 13	Bechtel Drawing	Revision 2
Operating Instruction (OI)-89	Baron II High Pressure Breathing Air Fill Procedure	Revision 1
TS 15.3.3.C	Component Cooling System	July 9, 1997
Final Safety Analysis Report (FSAR) 9.1	Component Cooling Water	June 2002
Operations Checklist 1-CL-CC-001	Component Cooling Unit 1	Revision 5 and 8
Operations Checklist 2-CL-CC-01	Component Cooling Unit 2	Revision 8
Piping and Instrument Diagram (P&ID) M-207, Sheet 3	Service Water	Revision 42
TS 15.3.3.A	Safety Injection and Residual Heat Removal Systems	September 23, 1997
FSAR 9.2	Residual Heat Removal (RHR)	June 2001
Operations Checklist CL 7A	Safety Injection System Checklist, Unit 1	Revision 16
TS 15.3.7	Auxiliary Electrical Systems	July 9, 1997

FSAR 8.9	Gas Turbine System (GT)	June 2002
Operations Checklist CL 16A	Gas Turbine G05	Revision 16
E-316	Single Line Diagrams Station Connections	Revision 16
Design Basis Document DBD-22	4160 VAC System	February 5, 1997
Training Handbook 11.20	Secondary Systems Descriptions: Emergency Breathing Air System	Revision 2

<u>1R05</u> <u>Fire Protection</u>

Fire Hazards Analysis Report	Fire Zone 556, Main Transformers, Unit 1	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 698, Main Transformers, Unit 2	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 771, P-206A & P-207A Fuel Oil Pump Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 772, T-176A Day Tank Room	August 17, 2001
CAP029108	1/2B-30, 480 Volt Motor Control Center Has Gaps Between Base and Access Plate	August 21, 2002
Fire Hazards Analysis Report	Fire Zone 776, P-206B & P-207B Fuel Oil Pump Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 511, Unit 1 Containment 21 Foot Elevation	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 520, Unit 1 Containment 66 Foot Elevation	August 17, 2001
Fire Hazard Analysis Report	Fire Zone 156, 1B32 Motor Control Center Room	August 17, 2001
Barrier/Penetration Drawing M-7-4-46	East Wall of Fire Zone 156	July 21, 1993
Fire Protection Evaluation Report, Table 5.2.6-1	Summary of PBNP Appendix R Exemptions: Unit 1 Motor Control Center Room Fire Fire Zone 156 (formerly Fire Zone 1)	August 17, 2001
Fire Hazard Analysis Report	Fire Zone 516, Unit 1 Containment 46 Foot Elevation	August 17, 2001

Fire Hazard Analysis Report	Fire Zone 318, Cable Spreading Room 26 Foot Elevation	August 17, 2001
Fire Drill Scenario	K-1A Waste Gas Compressor Cubicle	August 20, 2002
Fire Emergency Plan 4.10	Auxiliary Building	Revision 5
Fire Hazards Analysis Report	Fire Zone 209, Truck Access Area	August 17, 2001
CAP029115	Contamination Control During Fire Drill LTA	August 22, 2002

1R06 Flood Protection Measures

NP - 8.4.17	PBNP Flooding Barrier Control	Revision 0
DBD - T - 41	Hazards - Internal and External Flooding [Module A], Point Beach Nuclear Plant (PBNP) Topical Design Basis Document	Revision 0

1R07 Heat Sink Performance

Anatec Report NMC-PB11-15	Component Cooling Water HX 12C Eddy Current Inspection Report	August 23, 2002
Power Generation Technologies TIN 2002-1270	Point Beach Nuclear Plant Component Cooling Water Heat Exchangers HX-12C and HX-12D Thermal Performance Test Data Evaluation and Uncertainty Analysis	Revision 0
WO 9947346	Eddy Current Inspect Component Cooling Water Heat Exchanger	July 31, 2002
WO 0206227	Open/Close Component Cooling Water Heat Exchanger	August 1, 2002

1R08 Inservice Inspection Activities

WO 9925546	P-32A SW Pump Expansion Joint	November 17, 2001
WO 9924865	Install Anchors on Refueling Water Storage Tank (RWST)	June 5, 2001
CAP013801	Presence of Boric Acid Residue Not Recorded	April 11, 2001
CAP013906	Spring Hanger Concerns	April 26, 2001

CAPO000900	Spent Fuel Pool Heat Exchanger Fouling	August 9, 2001
CAP005467	G01 & G02 Emergency Diesel Generator Concerns	August 13, 2001
CAP001985	NRC Commitment to Inspection Unit 2 Internals Lift Rig Not Met	January 25, 2002
CAP002655	Support SI-1501R-3-2H2 Apparently Has The Wrong Type of Spring Can Installed	March 22, 2002
CAP003032	Evaluation of In Service Inspection (ISI) Examinations Are Creating Problems for AR Engineering	April 25, 2002
CAP028727	Relief Request For IWL	July 12, 2002
CAP013928	Keyway Snubber Mounting	May 1, 2002
NDE-168	Manual Ultrasonic Examination of Reactor Pressure Vessel (RPV) Flange-To-Upper Shell Weld	Revision 8
	Inservice Inspection Plan for U1R27 Outage	June 1, 2002

1R11 Licensed Operator Qualifications

TI 8.0 Attachment 6	Conduct of Simulator Training and Simulator Evaluation (STA Simulator Evaluation Summary)	Revision 4
TI 8.0 Attachment 4	Conduct of Simulator Training and Simulator Evaluation (Crew Simulator Evaluation Summary)	Revision 4
TI 8.0 Attachment 5	Conduct of Simulator Training and Simulator Evaluation (Individual Simulator Evaluation Summary)	Revision 4
Point Beach Form (PBF)-6097	Operations Watchstander Temporary Restriction Form	Revision 1
PBF-6413	LOR 2002 Operational JPM Exam Package E (Remedial)	Revision 1
QF-1040-04	Remediation/ Make-up Training Form	Revision 0
	Simulator Scenarios SES033	Revision 2
	Simulator Scenarios, SES060	Revision 1
	Simulator Scenarios SES027	Revision 4
	Simulator Scenario SES002	Revision 1

1R12 Maintenance Rule Implementation

NP 7.7.4	Scope and Risk Significant Determination for the Maintenance Rule	Revision 6
NP 7.7.5	Determining, Monitoring and Evaluating Performance Criteria for the Maintenance Rule	Revision 8
NP 7.7.6	Work Order Review and MPFF [Maintenance Preventable Functional Failure] Determination for the Maintenance Rule	Revision 3
Administrative Manual Procedure AM 3-4	Implementation of the Maintenance Rule at PBNP [Point Beach Nuclear Plant]	Revision 4
Memo NPM 2001-0251	2000 Annual Report for the Maintenance Rule	March 26, 2001
NPM 2002-0161	2001 Annual Report for the Maintenance Rule	March 28, 2002
NPM 2002-0175	2001 Annual Report for the Maintenance Rule: Maintenance Rule Performance Criteria for 2001	April 3, 2002
NPM 2002-0312	EAC [Engineering Advisory Committee] Meeting (RAGEA Relay)	June 13, 2002
Condition Report (CR) 01-3489	Ammeter for 1P-015A-M SI Pump Motor, at the 100 Amp Test Input, Yielded a Meter Reading That Was Out of Spec High	November 15, 2001
CR 01-1035	MRR [Metering, Relaying, and Regulation] System Has Achieved (a)(1) Status	March 30, 2001
CAP002234	Alarm Received From RAGEA Relay 2-27/59N TG01	February 18, 2002
CAP002692	Maintenance Rule Performance Criteria and Functional Failures Not Documented	March 27, 2002
CAP013729	Metering, Relaying and Regulation System A-1 Status	March 30, 2001
CAP028312	RAGEA Relay Alarm Came In On Unit 2	May 26, 2002
CAP028789	Failed Relay Test	July 19, 2002
Corrective Action CA003790	Track Completion of MRR System Action Plan to Return to (a)(2) Status	February 19, 2002

CA006768	Develop Corrective Action Plan Via Maintenance Rule Requirements [for MRR system Achieving (a)(1) Status]	April 4, 2001
Condition Evaluation CE010281	Perform a Condition Evaluation, per CAP028312 Level C, In Accordance With NP 5.3.1	May 29, 2002
Maintenance Rule Evaluation MRE000057	Perform a Maintenance Rule Evaluation, per CAP028789 Significance Level C, In Accordance With NP 7.7.5	July 23, 2002
	Performance Criteria Assessment for MRR Since 7/1/2001	September 16, 2002
	Documentation of Maintenance Rule Performance Criteria [MRR System]	June 29, 1998
	Function List for MRR Metering, Relaying and Regulation	September 16, 2002
	Work Orders for MRR with M, F or C in MPFF Field Initiated or Completed Between 6/1/2000 and 9/1/2002	September 16, 2002
CA025410	Ensure Performance Criteria [for the MRR System] Were Not Exceeded	May 28, 2002

<u>1R13 Maintenance Risk Assessment and Emergent Work Evaluation</u>

	E-1 Report for T07A2 (Work Week Schedule)	Run Date - July 1, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	July 1 - 5, 2002
	E-1 Report for T01A1 (Work Week Schedule)	Run Date - July 14, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	July 14-19, 2002
	E-1 Report for T10B1 (Work Week Schedule)	Run Date - July 22, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	July 22 - 26, 2002
	E-1 Report for T11A2 (Work Week Schedule)	Run Date - July 29, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	July 29 - August 2, 2002

	E-1 Report for U01A1 (Work Week Schedule)	Run Date - August 11, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	August 12 - 16, 2002
	E-1 Report for U02B1 (Work Week Schedule)	Run Date - August 17, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	August 19 - 23, 2002
	E-1 Report for U03A2 (Work Week Schedule)	Run Date - August 23 & 27, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	August 26 - 30, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	September 16 -20, 2002
	Daily Update of Core Damage Risk Profile (Safety Monitor)	September 23 -27, 2002
1 Routine Maintenance Procedure (RMP) 9056-1	Calibration and Testing of Safety Related Protective Relays A-05	Revision 11
NP 10.3.7	On-Line Safety Assessment	Revision 5
NP 10.3.7	On-Line Safety Assessment	Revision 6
	E-1 Report for T05A1	Run Date - August 5, 2002
NP10.3.7	On-Line Safety Assessment	Revision 6
	Weekly Core Damage Risk Profile (Safety Monitor	August 5 - 9, 2002

1R15 Operability Evaluations

Operability Determination CAP 028606	10 CFR Part 21 Notification for Greyboot Electrical Connectors	June 28, 2002
CAP 028606	Potential 10CFR21 Notification Relating To Greyboot “A” Connectors	June 26, 2002
OPR000022	2FIT-930, Spray Add Flow FIT, False Indication	Revision 0

Design Basis Document 11	Safety Injection and Containment Spray System	Revision 0
IT-02	High Head Safety Injection Pumps and Valves (Quarterly)	Revision 48
IT-06	Containment Spray Pumps and Valves (Quarterly) Unit 2	Revision 50
Abnormal Operating Procedure (AOP) 1.3	Transfer To Containment Sump Recirculation Unit 2	Revision 27
CAP003232	Continue to Investigate Unit #1 Sump ‘A’ Level Increase	May 9, 2002
PC 24	Containment Inspection Checklist Unit 1	April 11, 2002
PC 24	Containment Inspection Checklist Unit 1	May 23, 2002
	Various Chemistry Department Sump 'A' Chemistry Results for Hydrogen, pH, Cesium 137, Iodine 133, Fluorine 18, Nb 97, Br 82, As 76, Cobalt 58, Cobalt 60, Magnesium 54, Boron, Sodium, Tritium	March 2002 to July 2002
WO 2002-030	Investigation of Possible Service Water Leak	May 31, 2002
WO 2002-041	U1 Sump 'A' Possible Drain Blockage Investigation	June 10, 2002
SCR 2002-0215	Investigation of Possible Service Water Leak to Unit 1 Containment	May 24, 2002
Bechtel Drawing C-108	Base Slab Outline Plan and Sections	Revision 5
Westinghouse Drawing 684J971, Sheet 1A	P&ID Waste Disposal System	Revision E
Bechtel Drawing C-2130	Containment Structure Interior Reinforcing Plan El. 10'-0” & Details	Revision 5
Bechtel Drawing M-63	Piping Area Drawing Area 7 Containment Plan Below El. 21'-0”	Revision 8
CAP028877	Linear Indication Found on Valve 2AF-114	July 29, 2002
MRE000058	Maintenance Rule Evaluation	July 31, 2002
WO 991484	Aux Feedwater Turbine-Driven Pump Recirc Socket Weld Repair	April 18, 2002
WO 0210898	AF-114 Linear Indication Repair	July 29, 2002

WO 0211135	Visual Examination On Sample of Safety Related Valves	July 29, 2002
WO 0211136	Visual Examination On Sample of Safety Related Valves	July 29, 2002
WO 0211137	Visual Examination On Sample of Safety Related Valves	July 29, 2002
Drawing D-464532-1	Edward F STN Steel Univalve Stop Valve	February 3, 1967
Drawing C-464529	Edward F STN Steel Univalve Check Valve	August 9, 1967
CAP029201	Poor Timeliness In Resolving Potential Plant Problems	September 3, 2002
CAP028995	RMP Had Out of Spec Motor Amp Current for P32A SW Pump	August 8, 2002
CAP028999	Procedural Acceptance Criteria Too Conservative	August 8, 2002
RMP 9216-3	Service Water Pump Vibration Testing and Balancing for Post Maintenance Testing	Revision 6

1R16 Operator Workarounds

CAP028875	WOs for FIT-930 (Control board Indicators) Are Over Six Years Old	July 29, 2002
NP 2.1.4	Operator Workarounds	Revision 0
Design Basis Document 11	Safety injection and Containment Spray System	Revision 0
WO 9610973	2FIT-930 Provide Pipe Supports	
WO 9611993	1FIT-930 Provide Pipe Supports	
CAP007485	False NaOH Flow Indication	October 4, 1996
CAP023258	Spray Additive Tank Outlet Flow Indicated During Pump Test	September 13, 1994
Critical Safety Procedure CSP-Z.1	Response To High Containment Pressure	Revision 16
Deviation Document DD-CSP-Z.1	Response To High Containment Pressure	Revision 14
Emergency Operating Procedure (EOP)-0 Unit 1	Reactor Trip Or Safety injection	Revision 38

EOP 1.3 Unit 1	Transfer to Containment Sump Recirculation	Revision 27
FSAR Section 6.4	Containment Spray System	June 2001

1R17 Permanent Plant Modifications

MR 02-007	Fish Deflection System for the Intake Crib	February 25, 2002
NP 7.2.1	Plant Modifications	Revision 10, June 12, 2002

1R19 Post-Maintenance Testing

WO 0202670	Component Cooling Water Pump Preventative Maintenance	February 21, 2002
WO 0202672	Component Cooling Water Pump Preventive Maintenance Activity	July 23, 2002
IT 12	Component Cooling Water Pumps and Valves (Quarterly) Unit 1	Revision 26
DBD-02	Component Cooling Water Design Basis Document	June 25, 1999
CAP028780	Two Temperature Instruments Found Damaged After Calibration	July 18, 2002
CAP028293	2A06 Voltmeter on CO2 Found De-energized (after calibration)	July 16, 2002
IT 01	High Head Safety Injection Pumps and Valves (Quarterly) Unit 1	Revision 48
WO Plan for WO 9946698	Replace Stem/Plug/Seat Ring 1SI-00829C	February 18, 2002
IT 520B	Leakage Reduction and Preventive Maintenance Program Test of 1SI-896A & B, SI Pump Suction Valves and HHSI [High Head SI] System High Flow Test Line (Refueling) Unit 1	Revision 10
RMP 9216-1	Service Water Pump Motor Removal and Installation	Revision 3
RMP 9612-2	Service Water Pump Motor Removal, Installation and Maintenance	Revision 3
RMP 9216-3	Service Water Pump Vibration Testing and Balancing for Post Maintenance Testing	Revision 6
IT07A	P-32A Service Water Pump (Quarterly)	Revision 11

DBD-12	Service Water System	July 25, 1998
WO 0212107-MR 02-029	AFP Common Mini Recirc Header Check	September 12, 2002
SCR 2002-0359	Removal of Internals from AF-117 and Upgrade Open Function of AFW Pumps Mini-Recirc Valves to Safety-Related (MR 02-09)	September 5, 2002
SCR 2002-0377	AFW System Operability During Removal of Internals From Check Valve AF-117 (MR 02-029)	September 10, 20002
WO 9937845	RCS To P-10A/B RHR Pump Suction Header	August 8, 2002
CAP 029556	RH-0700 Leak Off Weld Could Not Be Made Due To Moisture In Line	September 26, 2002
CAP 029557	RH-0700 Leak Off Line Cap Installation	September 26, 2002
NP 10.2.4	Work Order Processing	Revision 8
IT-04	Low Head Safety Injection Pumps and Valves	Revision 45

1R20 Refueling and Outage Activities

Operations Procedure (OP) 3A	Power Operations to Hot Standby	Revision 61
OP3B	Reactor Shutdown	April 25, 2002
OP3C	Hot Standby to Cold Shutdown	Revision 89
NP 10.3.6	Outage Safety Review and Safety Assessment	Revision 10
	U1R27 Outage Safety Assessment Key Safety Functions	September 12, 2002
	U1R27 NP 10.3.6 Numerical & Color Analysis of Key Safety Functions	September 12, 2002
OP 7A	Placing Residual Heat Removal System In Operation	Revision 41
CL 1E	Containment Closure Checklist	Revision 4
	Tag Series 1 OP-7A Placing RHR Into Service	Rev 0-1

	Reload Safety Evaluation Point Beach Unit 1 Cycle 28	Revision 0
	Point Beach Nuclear Plant Core Operating Limits Report Unit 1 Cycle 28	Revision 0
	Unit 1 Hot Leg and Pressurizer Boron Concentration Graph for 9/12 - 9/19	
CL 10B	Service Water Safeguards Lineup	Revision 52
1 345KV 1F52-122 APS	Tag Series To Isolate The Unit 1 Generator Output Breaker For Work	Revision 0-1
1 13.8KV X-3 APS	1X-03 Transformer Maintenance	Revision 0-1
CL 2A	Defueled to Mode 6 Checklist	Revision 2
	As Found Evaluation of 1 HX-1A SG Manways (2)	
OM 3.10	Operations Personnel Assignments and Scheduling	Revision 13

1R22 Surveillance Testing

CAP029498	PBTP-121 G-02 EDG Modified ORT-3 Test Risk Assessment May Have Been Insufficient	September 23, 2002
Engineering Evaluation 2002-0022	Comparison of Shutdown versus Operating Risk for G02 ORT 3 Testing	Revision 0
Engineering Evaluation 2002-0022	Comparison of Shutdown versus Operating Risk for G02 ORT 3 Testing	Revision 1
Point Beach Test Procedure 121	G02 Auto Close Timing and Auto Close Permissive Testing	Revision 0
SCR 2002-0301	G-02 Auto Close Timing and Auto Close Permissive Testing	September 3, 2002
License Amendment Request 227	Technical Specification LCO 3.8.1, AC Sources Operating	May 29, 2002
	Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 224 to Facility Operating License No. DPR-24 and Amendment No. 209 to Facility Operating License No. DPR-27, Nuclear Management Company, LLC, Point Beach Nuclear Plant, Units 1 and 2, Docket Nos. 50-266 and 50-301	August 29, 2002

1ICP 02.005B	Engineered Safety Features System Logic Train B 31 Day Staggered Actuation Logic Test	Revision 2
ICP 13.007B-2	Emergency Diesel Generator G-04 Calibration Procedure	Revision 4
DBD-02	Emergency Diesel Generator System Design Basis Document	June 24, 1999
FSAR Section 7.3	Engineered Safety Features Actuation System	June 2002
FSAR Section 8.8	Diesel Generator (DG) System	June 2001
CAP028766	G-04 Instruments Out of Tolerance	July 17, 2002
TS 5.5.14	Safety Function Determination Program (SFDP), Unit 1 Amendment No. 201, Unit 2 Amendment No. 206	
Technical Requirements Manual (TRM) 4.14	Safety Function Determination Program	Revision 0
NP 10.3.8	Safety Function Determination Program	Revision 0
0-TS-RE-002	Power Range Detector Power Level Adjustment, Completed July 28, 2002	revision 4
CAP029052	N41 High Flux Trip Greater than TS Limit After Low Power Gain Adjustments	August 15, 2002
Reactor Operating Data 14	Power Range Detectors Unit 2, Cycle 26, Unit 2 Power Range Pot Settings	July 27-28, 2002
ACE 00864	ACE per CAP029052, Significance Level B	August 30, 2002
CAP028619	SI-987/851 Interlock Testing Methodology	June 27, 2002
IT-45	Safety Injection Valves (Quarterly) Unit - 2	Revision 43
EOP 1.3	Transfer To Containment Sump Recirculation	Revision 27
DBD 11	Reference 9.6.55, Interlock Sheets SI-1 to SI-14, Point Beach Safety Injection system	April 6, 1968 to May 6, 1969
DBD 11	Safety Injection and Containment Spray System	Revision 0
FSAR Section 6.2	Safety Injection System	June 2001

Westinghouse Drawing 499B466 Sheet 770C	Elementary Wiring Diagram SI Test Line Return 2SI-00897A, Point Beach Unit 2	Revision D
Westinghouse Drawing 499B466 Sheet 770D	Elementary Wiring Diagram SI Test Line Return Second Off Isolation 2SI-00897B, Point Beach Unit 2	Revision D
Westinghouse Drawing 499B466 Sheet 734C	Elementary Wiring Diagram 2P-10A RHR Pump Suction From Containment Sump B Motor 2SI-00851A-M, Point Beach Unit 2	Revision D
Westinghouse Drawing 499B466 Sheet 734D	Elementary Wiring Diagram 2P-10B RHR Pump Suction From Containment Sump B Motor 2SI-00851B-M, Point Beach Unit 2	Revision D

<u>1R23</u> <u>Temporary Plant Modifications</u>

Installation Work Order Plan (IWP) 97-049*E02	Upgrade Control Room Envelope Boundary - Control Room Outdoor Air Ducat Isolation Damper	March 9, 2002
WO 9941558	Support Electrical Work for MR 97-049*E01	May 3, 2002
WO 9941557	Support Mechanical Work for MR 97-049*E01	May 3, 2002
Design Input Checklist MR 97-049*E	Temporary Cooling for the Control/Computer Rooms and Control Room Outdoor Air Duct Isolation Damper	March 11, 2002
Design Input Checklist MR 97-049*E01	Temporary Cooling and Filtration for the Control/Computer Rooms	March 4, 2002
NPM 2001-0704	Conceptual Temporary Filtration System to Support LAR-221 and MR-97-049*E Control Room Envelope Upgrade Modification	October 18, 2001
NP 7.7.2	Seismic Qualification of Equipment	Revision 1
Bechtel Construction Drawing C-181	Concrete, Turbine Building - Class 1 Structure Plans at EL.26'-0” and EL. 44'-0”	
Bechtel Construction Drawing C-301	Column Schedule, Sheet 1	Revision 6
Temporary Procedure Change (TCN) 2002-0437	Control, Computer, and Cable Spreading Room Ventilation Systems	July 11, 2002

SCR 2002-0205	MR-97-049*E, Applicable Document Updates/Changes and Duct Sealing (Hardcasting)	Revision 1
TCN 2001-0796	OI-90, Control, Computer, and Cable Spreading Room Ventilation Systems	November 1, 2001
Operating Instructions (OI) 90	Control, Computer, and Cable Spreading Room Ventilation Systems	Revision 15
CAP028654	Control Room Ventilation Temporary Modification Concern	July 2, 2002
CAP028769	Regulator Review of MR 97-049*E, Control Room Envelope Upgrades	July 17, 2002
CAP028796	T-131 Hypochlorite Tank Leak	July 19, 2002
Temporary Modification 02-035	Sodium Hypochlorite Temporary Supply	July 26, 2002
SCR 2002-0290	TM 02-035, Sodium Hypochlorite Supply	July 26, 2002
TCN 2002-0472	Chlorination of Circulating Water Pump Suction Well(s) and Service Water In Automatic Mode	July 31, 2002
TCN 2002-0473	Chlorination of Service Water in Manual Mode	July 31, 2002
Chemistry Analytical Methods & Procedures (CAMP) 909.4	Chlorination of Circulating Water Pump Suction Well(s) and Service Water In Automatic Mode	Revision 3
CAMP 909.8	Chlorination of Service Water in Manual Mode	Revision 1

<u>EP6</u> <u>Drill Evaluation</u>

	Kewaunee Point Beach Nuclear Power Plant Emergency Preparedness Drill and Exercise Manual, Control Copy 40	August 1, 2002
CAP028952	August 1 Drill EAL for Site Emergency	August 5, 2002
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	Revision 2
PBNP Performance Indicator Evaluation Form	Emergency Classification/Notification/ Protective Action Recommendation Opportunities, Alert	August 2, 2002

PBNP Performance Indicator Evaluation Form	Emergency Classification/Notification/ Protective Action Recommendation Opportunities, Site Area Emergency	August 2, 2002
Emergency Response Position Narrative Log	Rad Chem Monitor	August 1, 2002
Emergency Response Position Narrative Log	Engineering Coordinator	August 1, 2002
Emergency Response Position Narrative Log	HPN/SRC Communicator	August 1, 2002
Emergency Response Position Narrative Log	EOF Manager	August 1, 2002
Emergency Response Position Narrative Log	EOF Communicator	August 1, 2002
Emergency Response Position Narrative Log	State and County Communicator	August 1, 2002
Emergency Response Position Narrative Log	Operations Coordinator	August 1, 2002
Emergency Response Position Narrative Log	Instrumentation and Control Lead	August 1, 2002
Emergency Response Position Narrative Log	Plant Status Monitor TSC	August 1, 2002
Emergency Response Position Narrative Log	ERF Communicator	August 1, 2002
Emergency Response Position Narrative Log	Mechanical Systems Engineer	August 1, 2002
Emergency Response Position Narrative Log	TSC Manager	August 1, 2002
Emergency Response Position Narrative Log	OSC RP Leader	August 1, 2002
Emergency Response Position Narrative Log	EOF Emergency Director	August 1, 2002
Emergency Response Position Narrative Log	Dose/PAR Coordinator	August 1, 2002
Participant Log	Duty Shift Supervisor (Simulator)	August 1, 2002

Emergency Preparedness Frill/Exercise Log	Observer, TSC and OSC	August 1, 2002
Emergency Preparedness Frill/Exercise Log	Controller, EOF	August 1, 2002
Controller Chronological Event Log	Operations Support Center	August 1, 2002
Controller Chronological Event Log	Emergency Operations Facility	August 1, 2002
JPIC Position Narrative Log	JPIC Manager	August 1, 2002

4AO1 Performance Indicator Verification

NP 5.2.16, Attachment C	NRC Performance Indicators. PI Data Calculation, Review and Approval	July 1, 2002
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	Revision 2

4A02 Identification and Resolution of Problems

CAP028952	August 1 Drill EAL for Site Emergency	August 5, 2002
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	Revision 2
PBNP Performance Indicator Evaluation Form	Emergency Classification/Notification/ Protective Action Recommendation Opportunities, Alert	August 2, 2002
PBNP Performance Indicator Evaluation Form	Emergency Classification/Notification/ Protective Action Recommendation Opportunities, Site Area Emergency	August 2, 2002
CAP028877	Linear Indication Found on Valve 2AF-114	July, 29, 2002
ACE000841	CAP028877 Apparent Cause Evaluation	July 31,2002

4A03 Event Follow-up

RCE 000055	Pressurizer Safety Valve Failure to Lift at Test Pressure	September 9, 2002

4A05 Other

	Reactor Head Penetration Ultrasonic Examination Data Sheet, Control Rod Drive Mechanism (CRDM) 1	October 3, 2002
	Reactor Head Penetration Ultrasonic Examination Data Sheet, CRDM 31	October 4, 2002
	Reactor Head Penetration Ultrasonic Examination Data Sheet, CRDM 32	October 4, 2002
	Reactor Head Penetration Ultrasonic Examination Data Sheet, CRDM 33	October 4, 2002
Westinghouse Design Specification 676413	Reactor Vessel	Revision 6
WCAP-14000	Structural Integrity Evaluation of Reactor Vessel Upper Head Penetrations to Support Continued Operation: Point Beach Units 1 and 2	September 2002
NMC Letter NRC 2002-0082	NRC Bulletin 2002-02: Reactor Pressure Vessel Head And Vessel Head Penetration Nozzle Inspection Programs - 30-Day Response	September 12, 2002
WEP-94-666	Final Report for the Reactor Vessel Head Penetration Inspection Performed on Point Beach Unit #1	May 17, 1994
NDE-757	Visual Examination For Leakage of Reactor Pressure Vessel Closure Head Penetrations	Revision 1
Point Beach Indication Disposition Report	CRDM Nozzle 1, PT Indication, Data Sheet 451-0003	September 29, 2002
Framatome ANP Procedure 54-ISI-100-09	Remote Ultrasonic Examination of Reactor Head Penetrations	September 9, 2002
Framatome ANP Procedure 54-ISI-137-00	Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations	February 15, 2002
Framatome ANP Procedure 54-ISI-244-06	Liquid Penetrant Examination of Reactor Vessel Head Penetrations From the Inside Surface	February 15, 2002
	Video Examination Report, VT-1, Unit 1 Reactor Pressure Vessel Head From Outside Surface	September 2002

Drawing 5019702	Point Beach Unit 1 CRDM Nozzle ID Temper Bead Weld Repair	Revision E
Drawing 117	Closure Head Sub-Assembly	Revision 3
Framatome Report 54-PQ-100-03	Demonstration of Axial and Circumferential Rotating UT Probes on Oconee CRDM Cracked Nozzle Specimens and EPRI/MRP Mockup G	September 31, 2001
Framatome Report 54-5016639-00	Reactor Vessel Head Penetration Leak Path Qualification Report	February 6, 2002
Framatome Report	Oconee Unit 2 CRDM Nozzle Ultrasonic Examination Results	May 15, 2001
Framatome Report	Oconee Unit 1 CRDM Nozzle Ultrasonic Examination Results	April 2, 2002
Framatome Report	Oconee Unit 3 CRDM Nozzle Ultrasonic Examination Results (Top Tool Down)	November 20, 2001